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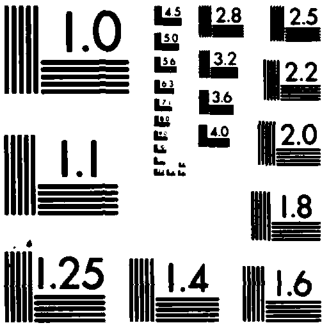

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CR 84.002

NAVAL CIVIL ENGINEERING LABORATORY
Port Hueneme, California

Sponsored by
NAVAL FACILITIES ENGINEERING COMMAND

COAL MIXTURE FUELS AT NAVY BASES
PHASE II OF ENGINEERING SERVICES FOR COAL CONVERSION GUIDANCE

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February 1984

BECHTEL GROUP, INC.
P.O. Box 3965
San Francisco, CA 94119

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METRIC CONVERSION FACTORS

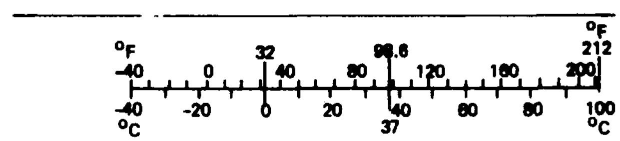
Approximate Conversions to Metric Measures

Symbol	When You Know	Multiply by	To Find	Symbol
		LENGTH		
in	inches	*2.5	centimeters	cm
ft	feet	30	centimeters	cm
yd	yards	0.9	meters	m
mi	miles	1.6	kilometers	km
		AREA		
in^2	square inches	6.5	square centimeters	cm^2
ft^2	square feet	0.09	square meters	m^2
yd^2	square yards	0.8	square meters	m^2
mi^2	square miles	2.6	square kilometers	km^2
	acres	0.4	hectares	ha
		MASS (weight)		
oz	ounces	28	grams	g
lb	pounds	0.45	kilograms	kg
	short tons (2,000 lb)	0.9	tonnes	t
		VOLUME		
tsp	teaspoons	5	milliliters	ml
Tbsp	tablespoons	15	milliliters	ml
fl oz	fluid ounces	30	milliliters	ml
c	cups	0.24	liters	l
pt	pints	0.47	liters	l
qt	quarts	0.95	liters	l
gal	gallons	3.8	liters	l
ft^3	cubic feet	0.03	cubic meters	m^3
yd^3	cubic yards	0.76	cubic meters	m^3
		TEMPERATURE (exact)		
°F	Fahrenheit temperature	5/9 (after subtracting 32)	Celsius temperature	°C

*1 in = 2.54 (exactly). For other exact conversions and more detailed tables, see NBS Misc. Publ. 286, Units of Weights and Measures, Price $2.25, SD Catalog No. C13.10:286.

Approximate Conversions from Metric Measures

Symbol	When You Know	Multiply by	To Find	Symbol
		LENGTH		
mm	millimeters	0.04	inches	in
cm	centimeters	0.4	inches	in
m	meters	3.3	feet	ft
m	meters	1.1	yards	yd
km	kilometers	0.6	miles	mi
		AREA		
cm^2	square centimeters	0.16	square inches	in^2
m^2	square meters	1.2	square yards	yd^2
km^2	square kilometers	0.4	square miles	mi^2
ha	hectares (10,000 m^2)	2.5	acres	
		MASS (weight)		
g	grams	0.035	ounces	oz
kg	kilograms	2.2	pounds	lb
t	tonnes (1,000 kg)	1.1	short tons	
		VOLUME		
ml	milliliters	0.03	fluid ounces	fl oz
l	liters	2.1	pints	pt
l	liters	1.06	quarts	qt
l	liters	0.26	gallons	gal
m^3	cubic meters	35	cubic feet	ft^3
m^3	cubic meters	1.3	cubic yards	yd^3
		TEMPERATURE (exact)		
°C	Celsius temperature	9/5 (then add 32)	Fahrenheit temperature	°F



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20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

A study defining feasibility and costs of preparation and utilization of coal mixture fuels at Navy bases was performed. The study established equipment requirements, flows, and capital and annual costs of coal-oil mixture and coal-water mixture preparation plants for Navy base heating systems generating between 100,000 lb/hr and 800,000 lb/hr of steam. Combustion

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properties of coal mixture fuels were analyzed. Procedures for calculating mixture fuel preparation and utilization costs at a typical Navy base were automated.

The attached user manual was prepared for a computer program that calculates flows and costs for coal-fired steam and power generation facilities at Navy bases. The manual describes computational methods, program input, program output, program data tables, program execution, error processing, testing procedures, and code structure. Appendices include a sample run and a listing of program data tables.

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Section 1

INTRODUCTION

The Naval Civil Engineering Laboratory (NCEL) at Port Hueneme, California is developing data and computational tools for calculating the cost of converting shore station heating and power generation facilities from high-priced oil and natural gas to lower-priced coal.

This report describes work performed by Bechtel Group, Inc., in Phase II of Navy Contract N62474-82-C-8290 with NCEL, entitled, "Engineering Services for Coal Conversion Guidance," a 15-month effort of three concurrent phases.

Phase I work included definition of a methodology for calculating coal facility life cycle costs using commercial economics, as well as the economic analysis methods customarily used by the Navy. It also included preparation of a computer program to permit converting from one of the forms of economic analysis into the other.

The Phase II work included development of a data base on the cost and performance of burning coal-water mixtures and coal-oil mixtures in retrofitted boilers, and incorporation of this information in a second computer program. This program calculates component and total costs of steam and power generation facilities for a Navy base of arbitrary configuration under a variety of user-chosen assumptions. The program calculates life cycle costs under commercial as well as Navy economic assumptions. The program includes data prepared for NCEL on previous studies and the new data generated in the Phase II work.

The Phase III work included updating a previous study for NCEL, which compared a variety of coal conversion technologies under several degrees of steam plant decentralization, and preparation of a third computer program to present the technology comparisons under a variety of

user-chosen assumptions. The program includes the capability of calculating life cycle costs using Navy or commercial economics. The Phase III data includes costs for converting coal to gaseous and liquid fuels developed in prior studies for NCEL.

The computer programs for the three phases were adapted from a computer program prepared previously for NCEL. There is a separate report for each phase o: the contract, and a separate user manual for the computer program for each phase.

1.1 OBJECTIVES

The objectives of the Phase II study were to:

- Prepare designs and estimate costs for on-base facilities to prepare coal-oil mixtures and coal-water mixtures to fuel existing boilers
- Assess the feasibility of retrofitting existing boilers to burn coal-oil and coal-water mixtures
- Prepare the Phase II computer program to automate the calculation of flows and costs for coal-oil mixture and coal-water mixture preparation and utilization

It is noted that the scope of the Phase II study did not include the examination of the feasibility and economics of retrofitting existing boilers for direct coal firing. At Navy bases that have adequate space for coal storage near the existing boilers, direct coal firing may offer attractive economics.

1.2 TECHNICAL APPROACH

To establish the bases for the Phase II work, background data were assembled and study assumptions were established. Subsequently, performance and cost analyses were carried out and the feasibility of retrofitting existing boilers was assessed. Finally, component and system cost calculations were automated by the construction of the Phase II computer program.

For background information, open literature data and Bechtel in-house information on the following topics were accumulated and examined: the incentives for considering mixture fuels, the impact of coal quality on its utilization, the commercial status of the technology, and results of previous derating studies.

Study assumptions included:

- Definition of the coal mixture fuel types and mixture ratios
- Selection of nominal coal and oil properties
- Definition of the size of mixture fuel storage facilities
- Setting of the sizes of mixture fuel preparation facility modules to span the range of sizes required by this study
- Identification of appropriate pollution control standards and equipment
- Setting of retrofit and derating requirements
- Selection of cost calculation methods and economic parameters

With these assumptions, analyses and assessments were carried out to calculate the performance and cost of modules in coal mixture fuel preparation facilities, and to determine the feasibility and costs of retrofitting boilers to coal mixture fuels. Sample calculations of performance and costs of coal mixture fuel utilization in central steam plants were prepared.

The Phase II computer program was constructed by adapting the existing NCEL computer program which calculates performance and costs for heating plants with coal-fired boilers. As part of this adaptation, the following were achieved:

- Addition of algorithms on coal mixture fuels to the existing routines
- Insertion of new routines on commercial economics from the Phase I computer program

- Review and update of the data base for the existing NCEL program
- Modification and reverification of the principal calculations of the program

The Phase II work referenced a number of Navy documents. References 1-1 through 1-4 describe the Navy economic analysis methodology used for calculation of the technology life cycle costs presented in this report. References 1-5 and 1-6 contain a data base on the performance and costs of coal fired boiler facilities and pollution control equipment. Reference 1-7 describes the existing NCEL computer program which was used in the construction of the Phase II computer program. Reference 1-8 provides Navy recommended differential inflation rates used in this report to prepare life cycle cost estimates. Comparison costs for burning oil in existing boilers are taken from Reference 1-9.

1.3 REPORT ORGANIZATION

Section 2 of this report summarizes information developed during the Phase II work on coal mixture fuel preparation plants, boiler retrofit feasibility, and costs of energy using coal mixture fuels. Section 3 provides details on the study methodology and gives background on coal mixture fuels. Section 4 provides descriptions and costs for coal mixture fuel preparation and storage systems. Section 5 discusses the factors affecting the convertibility of boilers to coal mixture fuels and presents retrofit equipment requirements and costs. Section 6 presents the mixture fuel system flow, capital costs, annual costs, and life cycle energy costs for preparation and utilization of coal mixture fuels in a 400,000 lb/hr central steam plant, and compares these costs with those of new coal-fired stoker boilers or using oil in existing boilers. Appendix A presents an update of certain cost and performance data for coal-fired boiler installations with pollution control that originally appeared in References 1-5 and 1-6, and were revised as part of the Phase II study. Appendix B presents a similar update of cogeneration performance data. Appendix C is a checklist of items to be considered when analyzing the feasibility of converting a boiler to coal mixture fuels.

Section 2

SUMMARY

This section summarizes the information developed in Phase II on coal mixture fuel preparation facilities, feasibility of boiler retrofit, and system costs for using coal mixture fuels at Navy bases.

Coal mixture fuels - pumpable *slurries of finely ground coal suspended* in liquids - offer a potential to retrofit boilers to use coal in place of higher-priced oil and natural gas.

This study analyzed the use of coal-oil and coal-water mixtures. Table 2-1 presents typical properties of coal mixture fuels.

In discussing the retrofit of boilers to coal mixture fuels, this report will distinguish between two types of boilers:

- Coal-capable boilers - boilers that were originally used with coal or were designed (sometimes incidentally) with the capability for coal use
- Non-coal-capable boilers - boilers designed originally to burn only oil or natural gas

2.1 COAL MIXTURE FUEL PREPARATION FACILITIES

Coal-oil and coal-water mixtures are prepared with commercially available processes and equipment. It is feasible to design and construct facilities at Navy shore stations to prepare coal mixture fuels. Such facilities include:

- Coal handling
- Coal grinding and slurry mixing
- Product storage

Table 2-1

TYPICAL COAL MIXTURE FUEL PROPERTIES

Property	Units	Coal-Oil Mixture	Coal-Water Mixture
Mixture Composition			
Coal	Wt %	50	60(1)
Oil	Wt %	50	N/A(2)
Water	Wt %	N/A	40
Mixture Heating Value	Btu/lb	16,400	6,000
Mixture Specific Gravity	Dimensionless	1.13	1.21
Combustion Efficiency in Typical Boiler	%	80	75
Coal Composition, As Received(3)			
Sulfur	Wt %	0.8	2
Ash	Wt %	6.1	20
Moisture	Wt %	10	10
Coal Heating Value			
As Received	Btu/lb	12,600	10,000
Dry Basis	Btu/lb	14,000	10,526
Oil Composition			
Sulfur	Wt %	1.0	N/A
Ash	Wt %	0.1	N/A
Oil Heating Value	Btu/lb	18,800	N/A

(1) The percent of coal in coal-water mixtures is expected to vary between 60 and 75 percent. A 60 percent coal concentration was used in this study to provide conservative estimation of required storage volumes and combustion efficiencies. High coal concentrations which may be feasible in large installations may prove impractical in industrial size installations.

(2) N/A means not applicable.

(3) Coal-water mixtures, made from either low-ash (or cleaned) coal or high-ash coal, are expected to burn acceptably in retrofitted coal-capable boilers. The achievement of maximum oil displacement is not affected by the coal ash content in coal-water mixtures, thus more economical eastern coals may be used. By contrast, low ash, high heating value coals are preferable in coal-oil mixtures to achieve good oil displacement.

Figure 2-1 shows the major functions of these facilities.

Table 2-2 shows two alternative design approaches considered for sizing the facilities in a coal mixture fuel preparation plant. The design based on annual average load proved to be lower in cost and was adopted for the study. In this design, the handling facilities and grinding and mixing facilities are sized to manufacture a mixture fuel at a rate equal to the annual average fuel demand rate. To supply the fuel requirements during the coldest season of the year, a storage facility is provided which holds up to 45 days of mixture fuel.

When designed for the annual average load design, the required capacity of the preparation facilities is lower, but a greater storage capacity is required. Table 2-3 presents the production and storage capacities to supply mixture fuels to Navy bases having steam loads between 100,000 and 800,000 pounds per hour and annual load factors of 25, 50, and 75 percent. The information in this table is based on the annual average load designs.

2.2 FEASIBILITY OF BOILER RETROFIT

The feasibility of retrofitting existing Navy boilers to coal mixture fuels must be established on a case-by-case basis. Each boiler considered for retrofit should be subjected to detailed engineering analysis to establish the extent and cost of modifications and any capacity derating. Based on previous studies, the following general observations are warranted:

- Retrofit is often feasible, without significant derating, for coal-capable boilers.
- Retrofit of boilers that were originally designed to burn only oil or natural gas normally requires extensive modifications, involves severe derating, and can seldom be economically justified. Coals with low ash fusion temperatures require excessively severe derating to avoid slag deposits and plugging in the boiler convection section.

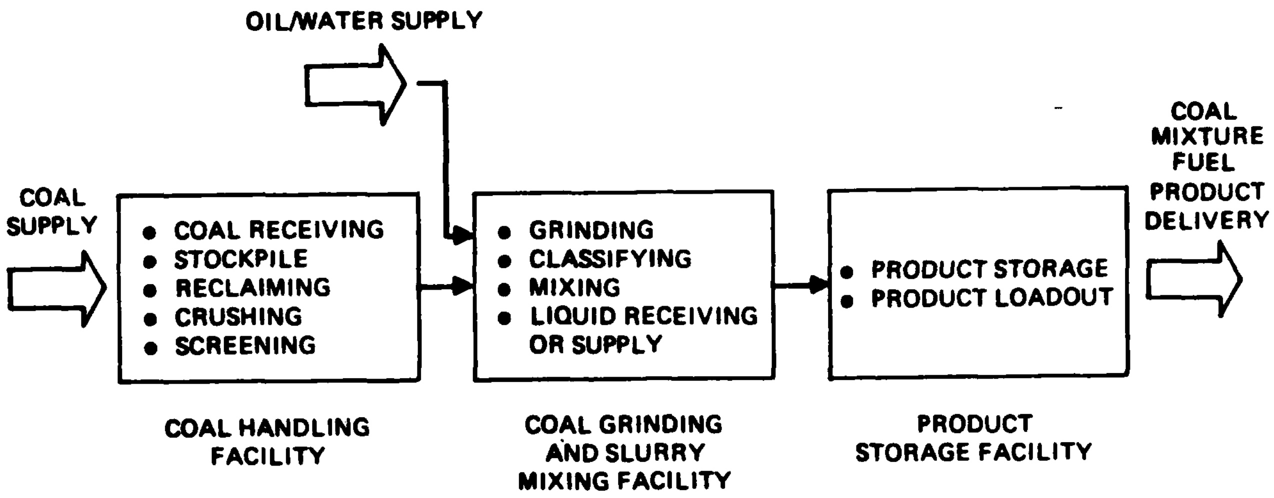

Figure 2-1 COAL MIXTURE FUEL PREPARATION PLANT MAJOR FUNCTIONS

Table 2-2

ALTERNATIVE DESIGNS FOR SIZING
COAL MIXTURE FUEL PREPARATION PLANTS

Facility	Peak Load Design	Annual Average Load Design(1)
Coal Handling	Size for Peak Load	Size for Annual Average Load
Coal Grinding and Slurry Mixing	Size for Peak Load	Size for Annual Average Load
Product Storage	Size to Accommodate Temporary Outages	Size to Store Cold Season Fuel Supply

(1) The annual average load is defined as the total annual steam production divided by 8,760 hours per year. The load is expected to vary through the year. Operation at peak load will occur only for a short duration during the coldest periods of the year.

Table 2-3

TYPICAL COAL MIXTURE FUEL PREPARATION FACILITY CAPACITIES

Shore Station Steam Demand		Coal-Oil Mixture Preparation Facility Capacity			Coal-Water Mixture Preparation Facility Capacity		
Peak Steam Load, 10^3 lb/hr	Annual Load Factor, %	Average Coal Handling Rate, tph(1)	Average Mixture Production Rate, tph	Mixture Storage Capacity, Barrels(2)	Average Coal Handling Rate, tph	Average Mixture Production Rate, tph	Mixture Fue Storage Capacity, Barrels(2
100	25	0.5	1.0	22,500	1.5	2.5	60,000
	50	1.0	2.0	15,000	3.0	5.0	40,000
	75	1.5	3.0	7,500	4.5	7.5	20,000
200	25	1.0	2.0	45,000	3.0	5.0	120,000
	50	2.0	4.0	30,000	6.0	10.0	80,000
	75	3.0	6.0	15,000	9.0	15.0	40,000
400	25	2.0	4.0	90,000	6.0	10.0	240,000
	50	4.0	8.0	60,000	12.0	20.0	160,000
	75	6.0	12.0	30,000	18.0	30.0	80,000
800	25	4.0	8.0	180,000	12.0	20.0	480,000
	50	8.0	16.0	120,000	24.0	40.0	320,000
	75	12.0	24.0	60,000	36.0	60.0	160,000

(1) The symbol tph denotes short tons per hours.
(2) The days of storage provided by the listed product storage capacities are as follows:

Load Factor, %	Storage, days
25	45
50	30
75	15

A day of storage supplies fuel at the annual peak fuel demand rate for one day. A barrel contains 42 gallons.

2.3 SYSTEM COSTS FOR USE OF COAL MIXTURE FUELS

Typical capital, first year, and life cycle costs for coal mixture fuel preparation and utilization are compared in Table 2-4 with costs for burning oil in existing boilers and costs for direct firing of coal in new stoker boilers. The systems are compared at a capacity of 400,000 lb/hr peak steam load and a load factor of 50 percent. The data in Table 2-4 were calculated for coal-mixture fuels burned in retrofitted coal-capable boilers without derating.

Capital costs in Table 2-4 include all costs associated with retrofitting an existing coal-capable boiler and installation of mixing and storage facilities. The capital cost for retrofitting an existing coal-capable boiler to coal mixture fuel firing was taken to be 10 percent of the cost of a new stoker boiler of the same capacity.(1)

In the comparison, no sulfur dioxide (SO_2) pollution control system is provided for the coal-oil mixture system, since its uncontrolled emissions do not exceed the assumed limit of 1.2 pounds of SO_2 per million Btu. For the coal-water mixture system and the direct coal-fired stoker system, SO_2 pollution control systems are provided because they are assumed to be using a high sulfur coal.

First year costs in Table 2-4 include oil, coal, and other operating and maintenance costs. The cost of oil is seen to dominate the annual costs in the existing oil-fired plants and with coal-oil mixture options.

The life cycle costs in Table 2-4 are constant dollar levelized costs calculated with the Navy economic methodology. The costs of steam are significantly affected by the differential inflation rate (DIR) for each type of purchased energy. DIR is the difference between the energy

(1)The 10 percent factor for retrofitting coal-capable boilers is taken from Bechtel experience. For non-coal-capable boilers, retrofitting costs will vary widely, and they cannot be priced in a general study of this type.

Table 2-4

COMPARATIVE COSTS OF STEAM FOR COAL MIXTURE FUELS IN CENTRAL STEAM PLANTS(1)

			Low Sulfur Coal			High Sulfur Coal	
Item	Units	Oil in Existing Boilers	Coal-Oil Mixtures in Retrofitted Boilers	Coal-Water Mixtures in Retrofitted Boilers	Coal in New Stoker Boilers	Coal-Water Mixtures in Retrofitted Boilers	Coal in New Stoker Boilers
Capital Cost							
Coal Handling	10^3 $	0	2,164	6,267	5,674	6,267	5,674
Grinding, Mixing	10^3 $	0	2,636	2,405	0	2,405	0
Slurry Storage	10^3 $	0	764	1,867	0	1,867	0
Boiler, Retrofit or New	10^3 $	0	1,873	1,873	18,731	1,873	18,731
Particulate Control	10^3 $	0	4,193	4,193	4,193	4,193	4,193
Sulfur Dioxide Control	10^3 $	0	0	0	0	8,049	8,049
Total Construction Cost	10^3 $	0	11,630	16,605	28,598	24,654	36,647
Startup Cost	10^3 $	0	1,279	1,827	3,174	2,712	4,031
Total Capital Cost	10^3 $	0	12,909	18,432	31,772	27,366	40,678
Round off to			12,900	18,400	31,800	27,400	40,700
First Year Operating and Maintenance Cost(2)							
Oil	10^3 $/yr	15,884	9,168	0	0	0	0
Coal	10^3 $/yr	0	2,356	5,887	5,519	5,887	5,519
Labor, Materials, etc.	10^3 $/yr	895	3,758	4,210	3,251	6,043	5,039
Total First Year Cost	10^3 $/yr	16,779	15,282	10,097	8,770	11,930	10,558
Round off to		16,800	15,300	10,100	8,800	11,900	10,600
Life Cycle Levelized Cost of Steam(3)							
Investment	$/$10^3$ lb	0.00	0.84	1.20	2.07	1.78	2.64
Oil	$/$10^3$ lb	28.05	16.19	0.00	0.00	0.00	0.00
Coal	$/$10^3$ lb	0.00	2.66	6.65	6.24	6.65	6.24
Labor, Materials, etc.	$/$10^3$ lb	0.77	2.53	2.70	2.06	4.15	3.44
Total Cost	$/$10^3$ lb	28.84	22.22	10.55	10.37	12.58	12.32
Round off to		28.80	22.20	10.60	10.40	12.60	12.30

(1) The plants are coal-designed and have a peak capacity of 400,000 lb/hr of steam and operate at an annual load factor of 50 percent. Costs are in fourth quarter 1982 dollars.
(2) The first-year cost category "Labor, Materials, etc." includes no capital charges, per Navy methodology.
(3) The life cycle costs are derived from present values for plants starting up in November 1987 and operating for 25 years. Differential inflation of energy costs over the operating life has been taken into account.

inflation rate and the general inflation rate. DIR percentages used in this study were taken from Reference 1-8 as follows:

- Coal: 5 percent/year
- Electricity: 6 percent/year
- Oil: 8 percent/year
- Natural gas: 10 percent/year

The following conclusions may be drawn from the cost comparisons of Table 2-4:

- Capital costs of retrofitting coal-capable units for coal mixture fuels are significantly lower than for a new coal-fired stoker boiler system.
- First year and life cycle levelized operating costs of coal-oil mixture systems are significantly higher than those of coal-water mixture or new coal-fired stoker boiler systems.
- Life cycle costs of steam from coal-water mixture systems approach those of new coal-fired stoker boiler systems.

Section 3

METHODOLOGY AND BACKGROUND

3.1 STUDY METHODOLOGY

The scope of the Phase II study required efforts to:

- Define flows and costs of coal mixture fuel preparation facilities
- Assess the feasibility of retrofitting boilers
- Calculate flows and costs for complete systems for preparation and utilization of mixture fuels
- Automate the cost calculation procedures

This section describes the methods used in this work.

3.1.1 Definition of Flows and Costs of Coal Mixture Fuel Preparation Facilities

For the design and cost estimating of fuel preparation facilities, Bechtel drew on expertise from several previous studies for private and institutional clients. Early in the study, it was determined that capital costs could be reduced by including seasonal product storage so that the handling, grinding, and mixing facilities could be designed for the annual average rather than the maximum mixture fuel demand rate. Grinding and mixing facilities spanning the required sizes of 100 to 800 thousand lb/hr steam supply were designed, and cost estimates were prepared by factoring from major equipment costs. Storage facilities were designed and costed in a similar way.

3.1.2 Assessment of the Feasibility of Retrofitting Boilers

The feasibility of retrofitting boilers to coal mixture fuels was assessed, drawing on expertise developed in several major Bechtel studies, including one for the Electric Power Research Institute (EPRI)

(Reference 3-1). Qualitative assessments were made of the feasibility of boiler retrofit, and comments were provided about factors influencing boiler derating. Equipment requirements for retrofit were determined, and costs were established in terms of percentage of new stoker boilers.

3.1.3 Calculation of Flows and Costs for Complete Systems

Representative flows and costs of central steam plants containing coal mixture fuel preparation facilities, retrofitted boilers, and pollution control facilities provided the bases for analyses of the cost of energy using coal mixture fuels. Such basic data were determined for a 400,000 lb/hr steam supply system and are included in Section 6. The Phase II computer program was used for these calculations. This program is designed to determine the required basic data for steam supply systems with capacities in the range of 100 to 800 thousand pounds per hour.

3.1.4 Automation of Cost Calculations

The procedures for calculating costs for utilizing coal mixture fuels were automated by construction of the Phase II computer program, entitled "COALM - Coal Conversion Cost Computer Program with Mixture Fuels," adapted from the computer program described in Reference 1-7. COALM has the following features:

- INFREE free-format input data interpretation retained from the Reference 1-7 program
- Routines to recognize and store user input data, built by updating and expanding the Reference 1-7 program
- Routines to calculate plant component performance, costs, and plant total costs, built by updating and adding to the Reference 1-7 program
- A file of tables of component costs versus capacity, built by updating and adding to the file of the Reference 1-7 program
- Routines retained from the Reference 1-7 program to read and list tables and to retrieve table data

- A routine adapted from the Reference 1-7 program to calculate present values and levelized costs according to Navy economics as described in References 1-1 through 1-4

- Routines to calculate cash flows and pay back periods using Navy economics described in the Phase I report

- Routines to calculate life cycle costs according to the private sector economics described in the Phase I report

A user manual for the Phase II computer program has been prepared as a separate document (Reference 3-1).

The data base for the Reference 1-7 computer program was provided in References 1-5 and 1-6. As an initial work element in the Phase II effort, the Reference 1-7 program and the data base were reviewed for correctness and consistency. Consistency of the data base was achieved by the preparation of cost and performance update tables, included as Appendices A and B of this report. The Peference 1-7 program was then modified accordingly. Performance and costs calculated by the program for steam generation, pollution control, cogeneration, and coal and ash handling were verified.

3.2 TECHNICAL BACKGROUND

The term "coal mixture fuels" is used to designate the following slurries of finely ground coal in a liquid:

- Coal-oil mixtures

- Coal-water mixtures

3.2.1 Potential Advantages of Mixture Fuels

Coal mixture fuels offer a possible way to substitute coal for oil or natural gas in existing boilers. These fuels are attractive because:

- Slurry preparation facilities can be located away from the boilers, as may be required by space limitations or aesthetic considerations that preclude retrofit to pulverized coal or stoker firing.

- Mixture fuels are expected to be less expensive than fuel oil or natural gas.

- Capital required to retrofit an existing coal capable boiler to coal mixture fuels should be less than the capital to acquire a new coal-fired boiler.

3.2.2 Coal Quality in Mixture Fuels

Coal selection for a coal mixture fuel is governed by two major objectives, namely, to hold derating to a minimum and to maximize oil displacement.

For a given existing plant, the required derating is a strong function of the percentage and properties of the ash in the coal used in the mixture fuel. Derating will become more severe as the percentage of ash increases. Conversely, derating can be avoided or minimized if the mixture fuels are made with coals of low ash content (i.e., clean coals).

In regard to oil displacement, in a coal-oil mixture only a fraction of the heating value is supplied by the coal and the balance by the oil required to keep the slurry fluid. Consequently, the higher the heating value of the coal, the greater the number of displaced oil Btus. Thus, for coal-oil mixtures, it is always desirable to use coals with high heating values. And, since ash does not contribute to the heating value, it is desirable to use low ash coals for increased oil displacement when making coal-oil mixtures.

In coal-water mixtures, all the heating value is supplied by the coal. Consequently, from the point of view of oil displacement alone, there is no incentive to use clean coals in coal-water mixtures. However, while coal-water mixtures made with high ash ordinary coals are expected to burn satisfactorily in coal-capable boilers, the high ash content will increase the size of ash removal equipment and will also require operating and maintenance attention to burner tips, soot-blowing equipment, and boiler tube banks susceptible to plugging. Limitations on coal quality must be determined during the conversion feasibility analysis performed for each boiler considered for retrofit.

A requirement for clean coals is likely to increase the cost of the coal mixture fuel (expressed in dollars per million Btu), and it may restrict the possible sources of coal supply, since there are geographical limitations on where high heating value, low ash, or cleaned coals can be obtained. Table 3-1 summarizes the coal quality recommended for various combinations of mixture fuel type and boiler design.

Table 3-1

RECOMMENDED COAL QUALITY

Mixture Fuel Type	Boiler Design	Recommended Coal Quality
Coal-oil	Oil or Gas Designed	Clean Coal
Coal-oil	Coal-capable	Clean Coal
Coal-water	Oil or Gas Designed	Clean Coal
Coal-water	Coal-capable	Raw or Clean Coal

A significant fraction of the Navy's boiler capacity consists of coal-capable boilers, especially in older shore stations in the eastern United States. For these, firing of coal-water mixtures may be more economical than the alternative of installing new coal-fired boilers, particularly since competitively priced plentiful eastern coals could be used.

3.2.3 Commercialization Status

Coal-oil mixtures are now being burned commercially. The 120 MWe Unit 1 of the Paul L. Bartow Plant of Florida Power Corporation has been in continuous operation, firing coal-oil mixture, since startup on July 18, 1982. The coal-oil mixture for this plant is made in a nearby location by COMCO, transported to the Bartow Plant by barge, and stored at the plant in tanks agitated by large paddles to prevent settling. Although the Bartow unit is utilizing coal-oil mixture commercially, the operating and maintenance history accumulated so far is not extensive, and there is no assurance that unforeseen problems will not occur over the next few years of operation.

Coal-oil mixtures have also been tested in extended firings at a converted 400 megawatt oil-fired boiler at Sanford Power Plant facility of the Florida Power and Light Company. This test demonstrated satisfactory combustion control and achievement of thermal efficiencies close to that of oil alone. Some boiler derating was accepted to prevent deleterious effects from slag. Burner tip life of three months was achieved after experimentation during the tests.

Coal-water mixture technology is not yet commercially ready. Coal-water mixture firings have been conducted in pilot scale tests as indicated in Table 3-2.

Table 3-2

COAL-WATER MIXTURE PILOT COMBUSTION EXPERIENCE

Company	Firing System(1)	Fuel Composition and Results
Jersey Central Power and Light (1961)	Cyclone furnace	Mixture with 67% coal tested - stable combustion obtained
Atlantic Research Corporation	1×10^6 Btu/hr refractory-lined burner	Mixture with 65% to 70% coal burned with stable flame
Alfred University Research Foundation/Babcock & Wilcox	4×10^6 Btu/hr burner	12 tons of mixtures with 70% coal tested with stable flame
Carbogel AB (Sweden)	12×10^6 Btu/hr burner	Stable combustion of mixture with 70% coal in open air and tunnel tests
Pittsburgh Energy Technology Center (1981-3)	24×10^6 Btu/hr water tube boiler, burners with air atomization and tungsten carbide inserts	Stable flame achieved; several hundred hours of 6-hour tests with variety of coals; life of non-optimized burner 200 hours on coal-water mixtures, 1,000 hours on coal-oil mixtures.

(1) All test reports indicated that burner design is critical and requires development

Further steps required to achieve commercial readiness of coal-water mixture in boilers include: development of suitable burners with adequate use life; demonstration of suitable instrumentation and control schemes; identification of all pollution control requirements; and extensive full-scale tests to confirm the pilot scale results and to derive scale-up parameters.

Coal-water mixtures are offered for testing by several manufacturers, but quality standards have not yet been established, and not all purchased coal-water mixtures may give satisfactory performance. Most offerers of coal-water mixtures attempt to achieve stability against slurry settling by addition of polymers and surfactants. Until mixture stability becomes reliable and predictable, users of mixture fuels must rely on mechanical agitation to prevent slurry settling in storage.

It should be noted that a boiler manufacturer must develop a special burner for coal mixture fuel for each of its boiler types to be converted. The buyer of a conversion to coal mixture fuels should ascertain whether adequate burners have been developed for the particular boilers to be converted. The test experience at Pittsburgh Energy Technology Center (PETC) indicates that burner life may be unacceptably short with coal-water mixtures. PETC will test a different type of burner in Fiscal Year 1984 which may eliminate the problem of short burner life with mixture fuels. Until burners with extended life are developed, users of coal mixture fuels should anticipate frequent burner or burner tip replacement in their operating and maintenance planning.

3.2.4 Results of Previous Retrofitting Studies

As a general rule, boilers formerly fired with coal but later converted to oil or gas firing, or boilers designed with the capability of burning coal in the future, are likely to be retrofitted to burn coal mixture fuels without derating. Studies show that boilers originally designed only for oil or gas as fuels are likely to require significant modifications and/or derating for retrofitting to coal mixture fuels.

The Bechtel study on coal-oil mixture utilization for EPRI (Reference 3-2) included examination of six site-specific oil-fired utility boiler installations considered for conversion. These analyses included extensive computer calculations of heat transfer in the boiler. Following are some of the major findings from this boiler conversion study:

- One of the six boilers was originally built as coal-capable. After retrofit, this boiler should be able to operate at 100 percent of design capacity with coal-oil mixtures containing 50 weight percent of either of the coals considered in the study.(1)

- The other five boilers would suffer load deratings, ranging between 27 and 66 percent, after retrofit to coal-oil mixtures.

- The analyses indicate that when the coal-oil mixtures are burned in furnances of oil-designed boilers, the ash forms a slag which deposits on furnace wall tubes. This reduces the heat transfer rate, resulting in higher furnance exit gas temperatures. If fired at full rating with coal-oil mixture fuels, the furnace exit gas temperature for such a boiler would be higher than when the boiler is operated on fuel oil, and higher than in a comparable boiler designed for coal. Despite the higher luminosity of a coal flame, the heat transfer rates in the furnance are reduced because the slag deposits partially insulate the furnace wall tubes. The surface temperature of the slag deposits were calculated in the study to be as much as 500°F to 1500°F higher than the temperature of the water in the tubes. In contrast, when firing oil, the furnace wall tubes remain clean, and the surface temperature of the tubes is between 100°F to 200°F higher than the temperature of the water in the tubes.

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(1) The two coals and their key ash properties were:

Coal Type	Ash Content of Coal	Ash Initial Deformation Temperature
Kittaning	6.8%	2700°F
Pocahontas	5.0%	2080°F

- In all cases, the most severe derating would occur with the coal-oil mixture made with the low ash fusion temperature coal (Pocahontas coal). The boilers would be more severely derated for Pocahontas coal-oil mixture in order to maintain the furnace exit temperature below the coal ash fusion temperature, so that uncontrolable deposition on convection pass tubes would not occur.

- Limitation of convection pass tube erosion by fly ash particles is the reason for derating in cases where coal-oil mixture is made with the high ash fusion temperature coal (Kittaning coal). Erosion is expected when oil-designed boilers are switched to coal mixture fuels, because design gas velocities are higher in oil-designed boilers than in coal-designed boilers. A gas velocity of 70 feet per second is considered tolerable for the coal-oil mixture with Kittaning coal.

Section 4

COAL MIXTURE FUEL PREPARATION

This section discusses facility components, sizes, and costs for a coal mixture fuel preparation plant.

4.1 MIXTURE PREPARATION PLANTS

A coal mixture fuel preparation plant includes facilities for coal handling, coal grinding and slurry mixing, and product storage.

4.1.1 Coal-Oil Mixture Preparation Plant

Figure 4-1 is a schematic diagram that shows the components and sequence of operations in a coal-oil mixture preparation plant. In the coal handling facility, coal delivered in bottom-dump rail cars is unloaded, stockpiled, reclaimed, and crushed to a size of 3/4 inch and less.

In the coal grinding and slurry mixing facility, the coal is simultaneously dried and ground to approximately face powder consistency (70 percent minus 200 mesh) in a bowl mill. Heat for drying is provided by a combustor fired with natural gas. The pulverized coal is then mixed with fuel oil and pumped to storage.

The mixture fuel is supplied to the Navy base heating plants from the product storage facility. A small flow of auxiliary steam from the heating plants is used to maintain the stored coal-oil mixture at a pumpable temperature in cold weather.

4.1.2 Coal-Water Mixture Preparation Plant

Figure 4-2 is a schematic diagram that shows the components and sequence of operations in a coal-water mixture preparation plant. In the coal handling facility, coal delivered in bottom-dump cars is unloaded, stockpiled, reclaimed, and crushed to a size of 3/4 inch and less.

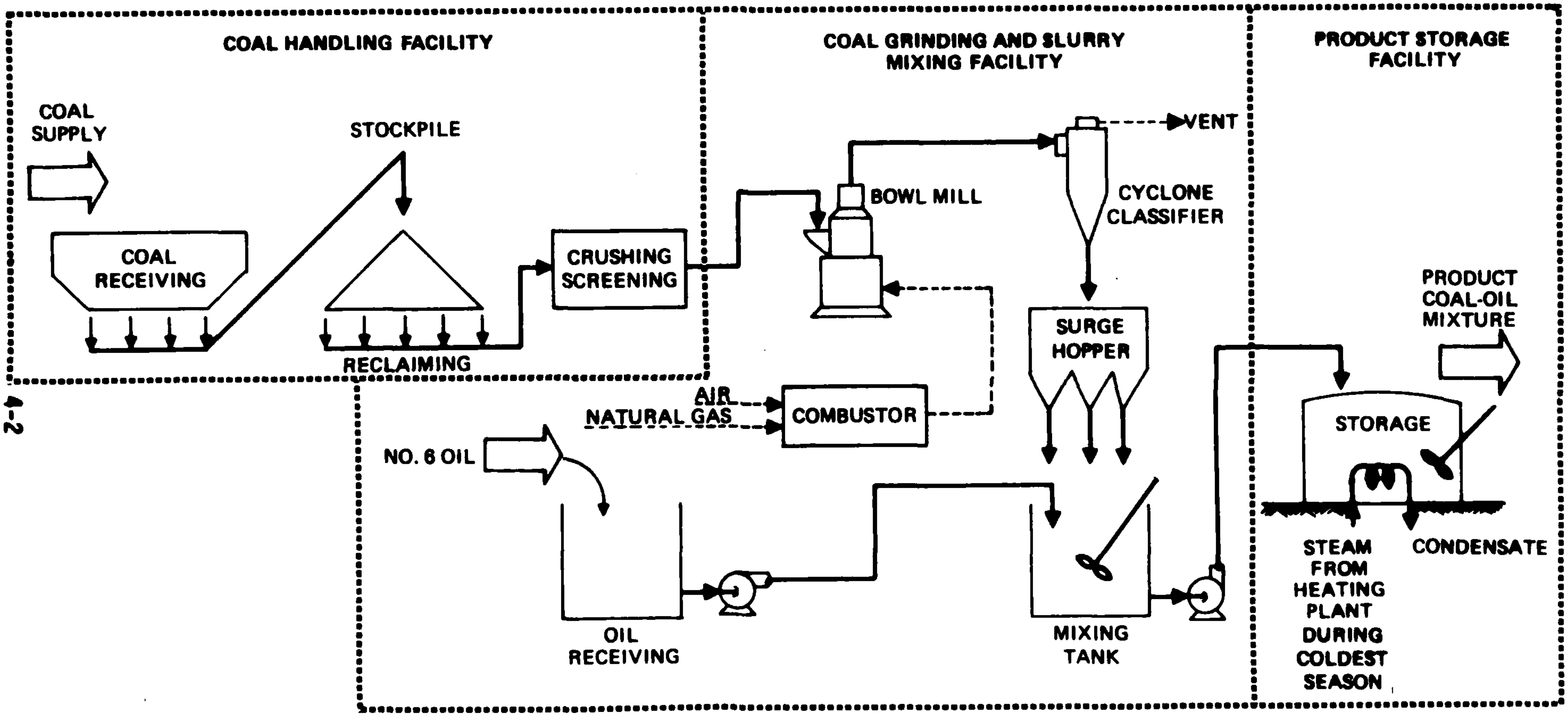


Figure 4-1 PROCESS SCHEMATIC DIAGRAM: COAL-OIL MIXTURE PREPARATION PLANT

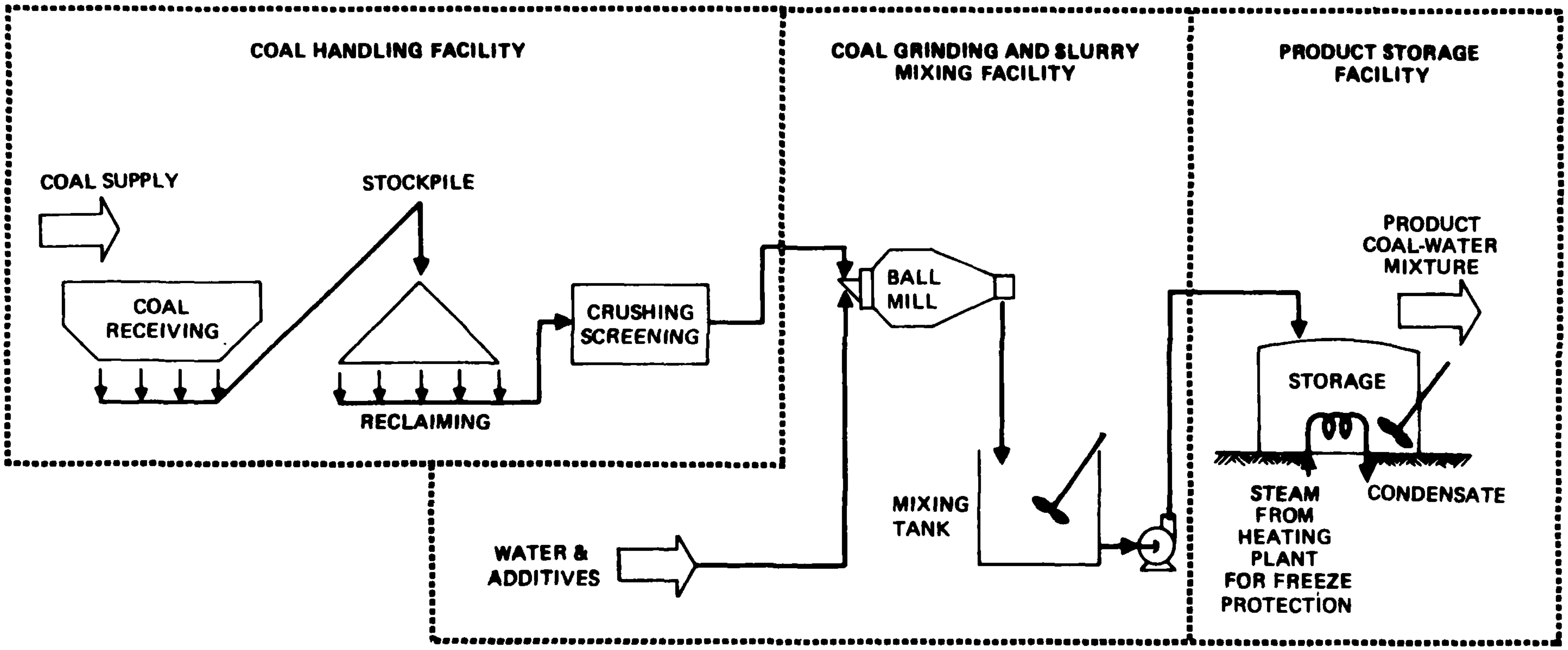


Figure 4-2 PROCESS SCHEMATIC DIAGRAM: COAL-WATER MIXTURE PREPARATION PLANT

In the coal grinding and slurry mixing facility, the coal is ground to approximately face powder consistency (70 percent minus 200 mesh) in a ball mill. The grinding operation is performed after mixing with water and additives. The slurry is then agitated to a uniform consistency in a mixing tank and is pumped to storage.

The mixture fuel is supplied to the Navy base heating plants from the product storage facility. A small flow of auxiliary steam from the heating plants is used to prevent freeze-up during cold weather.

4.2 MIXTURE PREPARATION PLANT SIZING

4.2.1 Nominal versus Design Capacity

It is convenient to distinguish between nominal and design capacity of a coal grinding and slurry mixing facility. The two capacities are defined as follows:

- Nominal capacity is the average output of the facility over an extended period of time.
- Design capacity is the maximum rated capacity of the equipment in the facility.

The nominal capacity is selected to match the required fuel supply rate for the Navy base in question. It is related to the design capacity as follows:

$$\text{Nominal Capacity} = \text{Design Capacity} \times \text{Equipment Availability}$$

A representative availability of 60 percent for coal grinding equipment has been used in this study. Accordingly, the design capacity must be 67 percent greater than the desired nominal capacity.

4.2.2 Selection of Annual Average Load Design

Two alternative designs for mixture fuel preparation facilities were considered during the study: a peak load design and an annual average load design. The two designs differ as follows:

- Peak Load Design
  - Coal handling, coal grinding and slurry mixing facilities are sized to a nominal capacity equal to the peak fuel demand rate
  - Product storage facilities are sized to accommodate temporary outages when coal handling facilities and coal grinding and slurry mixing facilities are undergoing maintenance
- Annual Average Load Design
  - Coal handling facilities and coal grinding and slurry mixing facilities are sized to a nominal capacity equal to the annual average fuel demand rate
  - Product storage facilities are sized to store the extra fuel required for peak loads during the cold season of the year

Of the two designs, the annual average load design proved to be lower in cost. As an example, in a plant designed for a maximum steam demand of 800,000 lb/hr and an annual load factor of 25 percent, the annual average load design has total construction costs 27 percent lower than the peak load design. Consequently, the annual average load design was adopted for this study.

In the annual average load design, the required amount of seasonal storage depends on the annual load factor and also upon the annual load profile of the base. For a given base, a study of demand histories and weather data will permit calculation of the required seasonal storage.

In studies that are not site-specific, the following formula, developed for steam demand curves of the Philadelphia Naval Shipyard, may be used:

$$\left\{\begin{array}{l}\text{Days of Storage}\\ \text{at Peak Annual}\\ \text{Demand Rate}\end{array}\right\} = \left\{\begin{array}{c}60\\ \text{Days}\end{array}\right\} \times \left\{1 - \frac{\text{Percent Load Factor}}{100}\right\}$$

In the formula, 60 days is a fit constant. For a load factor of 50 percent, the formula shows that the storage facility should be large enough to supply fuel at the peak demand rate continuously for 30 days.

4.2.3 Mass and Heat Flow Relationships

Coal mixture fuel preparation rates and facility sizes were calculated using the following data:

- 50 weight percent coal in coal-oil mixtures
- 60 weight percent coal in coal-water mixtures
- Coal composition and heating values as given in Table 4-1
- Oil composition and heating values as given in Table 4-2
- 80 percent boiler efficiency for coal-oil mixtures
- 75 percent boiler efficiency for coal-water mixtures
- 1000 Btu/lb latent heat of evaporation of water

Boiler efficiency is defined as:

$$\left\{\begin{array}{l}\text{Boiler}\\ \text{Efficiency,}\\ \text{percent}\end{array}\right\} = \left\{\frac{\text{Btu Transferred to Steam/lb Fuel}}{\text{Btu Higher Heating Value/lb Fuel}}\right\} \times (100\%)$$

Table 4-1

COAL COMPOSITION AND HEATING VALUE

Constituent/ Property	Units	Coal for Coal-Oil Mixtures (As Dried)	Coal for Coal-Water Mixtures(1) (As Received)
Carbon	Wt %	79.0	60.4
Hydrogen	Wt %	5.1	3.7
Oxygen	Wt %	6.9	6.0
Nitrogen	Wt %	1.3	1.4
Sulfur	Wt %	0.9	2.0
Ash	Wt %	6.8	21.5
Moisture	Wt %	0.0	5.0
Higher Heating Value			
As Received	Btu/lb	12,600	10,000
Dry	Btu/lb	14,000	10,526

(1) The high ash coal shown here is a "worst case" Eastern coal for coal-capable boilers. For many applications it is desirable to limit the ash level to 15 percent or below.

Table 4-2

OIL COMPOSITION AND HEATING VALUE

Constituent/ Property	Units	Venezuelan Number 6 Oil
Carbon	Wt %	86.5
Hydrogen	Wt %	11.1
Oxygen	Wt %	0.9
Nitrogen	Wt %	0.4
Sulfur	Wt %	1.0
Ash	Wt %	0.1
Moisture	Wt %	0.0
Higher Heating Value	Btu/lb	18,800

The lower combustion efficiency assumed for coal-water mixtures takes into account the heat required to evaporate the water in the coal-water slurry which is not recoverable.

4.2.4 Plant Sizes

Navy base heating system capacities considered in the study include 100, 200, 400, and 800 x 10^3 lb/hr of steaming capacity. Fuel preparation plant capacities were chosen to adequately span the above capacities for complete heating systems.

- Coal handling facilities spanning these capacities were described in Reference 1-5.
- Coal grinding and slurry mixing facility capacities for design and costing were chosen so as to satisfy the mixture fuel requirements at 50 percent load factor for systems with capacities between 100 and 800 x 10^3 lb/hr. For slightly higher or lower requirements, costs can be validly obtained by extrapolation from the data points given.
- Mixture fuel storage capacities completely span the system capacity and load factor range of interest.

All of the preparation facilities considered in the study require equipment sizes which are available commercially. For instance, the required bowl mill capacities do not exceed 15 tons per hour, and the ball mill capacities do not exceed 45 tons per hour. Both bowl mills and ball mills are available with capacities in excess of 100 tons per hour.

4.3 CONSTRUCTION AND OPERATING COSTS

4.3.1 Coal Handling Facility Costs

Costs for the coal handling facility are given in Reference 1-5 and were escalated to fourth quarter 1982 dollars in this study.

4.3.2 Coal Grinding and Coal-Oil Slurry Mixing Facility Costs

Table 4-3 presents the construction and annual operating costs for coal grinding and coal-oil slurry mixing facilities, as a function of capacity in tons per hour (tph).

If no hot flue gas is available, natural gas is required to dry the coal in the bowl mill. The quantity is proportional to the amount of coal processed. For example, a coal with as-received moisture of 10 percent requires 311 standard cubic feet of natural gas per ton of moisture-free coal.

Table 4-3

CONSTRUCTION AND OPERATING COSTS OF
COAL GRINDING AND COAL-OIL SLURRY MIXING FACILITIES

Nominal Mixture Preparation Rate, tph(1)	Total Construction Cost, $1000(2)	Annual Operating Costs		
		Materials $1000/yr(2)	Labor Manhours/yr	Electricity, MWh/yr
2.16	1,300	62.4	10,710	307
5.4	2,250	108.0	14,560	570
16.2	3,400	163.2	18,190	1,577

(1) The nominal mixture preparation rate is 0.6 times the design preparation rate (reflecting 60 percent availability of the preparation plant grinding equipment).
(2) Costs are in fourth quarter 1982 dollars.

The total construction costs in Table 4-3 were factored from vendor-quoted major equipment costs. The indicated mixture preparation rates cover the annual average fuel demand for plants of 100,000 to 800,000 lb/hr steaming capacity.

4.3.3 Coal Grinding and Coal-Water Slurry Mixing Facility Costs

Table 4-4 presents the construction and annual operating cost requirements for coal grinding and coal-water slurry mixing facilities, as a function of capacity in tons per hour (tph). The total construction costs in Table 4-4 were factored from vendor-quoted equipment costs. The indicated mixture preparation rates cover the annual average fuel demand for plants of 100,000 to 800,000 lb/hr steaming capacity.

Table 4-4

CONSTRUCTION AND OPERATING COSTS OF COAL GRINDING AND COAL-WATER SLURRY MIXING FACILITIES

Nominal Mixture Preparation Rate, tph(1)	Total Construction Cost, $1000(2)	Annual Operating Costs		
		Materials $1000/yr(2)	Labor Manhours/yr	Electricity, MWh/yr
5	1,130	54.2	7,440	394
15	1,920	92.2	10,370	1,090
45	3,780	181.0	16,510	3,110

(1) The nominal mixture preparation rate is 0.6 times the design preparation rate (reflecting 60 percent availability of the preparation plant grinding equipment).

(2) Costs are in fourth quarter 1982 dollars.

4.3.4 Coal Mixture Fuel Storage Costs

Table 4-5 presents the construction and annual operating costs for the coal mixture fuel storage facility, as a function of capacity in barrels. The range of storage capacities covers 10 to 60 days of storage for plants ranging in steaming rate from 100,000 to 800,000 lb/hr.

Steam required for heating the mixture fuel for freeze protection and enhanced flow characteristics while in storage is 68 pounds of steam per year per barrel of mixture fuel storage capacity. This steam allowance includes heat tracing of key piping and valves required in some climates.

Table 4-5

CONSTRUCTION AND OPERATING COSTS OF THE COAL MIXTURE FUEL STORAGE FACILITY

Storage Capacity, Barrels	Total Construction Cost, $1000(1)	Annual Operating Costs	
		Materials, $1000/yr(1)	Labor, Manhours/yr
4,000	120	6.0	2,280
8,000	200	10.0	2,410
16,000	300	15.0	2,580
32,000	500	25.0	2,910
64,000	800	40.0	3,410
128,000	1,600	80.0	4,750
256,000	3,200	160.0	7,410
512,000	6,400	320.0	12,750

(1) Costs are in fourth quarter 1982 dollars.

Section 5

COAL MIXTURE FUEL UTILIZATION

This section outlines the technical issues which need to be considered when an existing boiler is studied to determine the feasibility of converting it to coal-mixture fuel utilization. Related background information on this subject was presented earlier in Section 3.2.

5.1 FACTORS AFFECTING BOILER CONVERTIBILITY

Factors affecting the feasibility of converting an existing boiler for coal mixture fuels include:

- Mixture fuel combustion properties
- Effects of ash
- Effects of equipment type
- Acceptable boiler derating

These factors will be discussed mainly in the context of conversion of a boiler designed specifically for oil or gas. As indicated in Section 3.2, coal-capable boilers are adequately designed in most cases to accommodate most coal mixture fuels.

5.1.1 Mixture Fuel Combustion Properties

Flame stability, flame temperature, flame luminosity, and flame size are major combustion properties affecting retrofit feasibility.

The capability to maintain a stable flame has been successfully demonstrated for both coal-oil and coal-water fuels. However, neither fuel has been tested under enough different conditions to rule out possible anomalous behavior. Burner modifications, at times through trial and error, are usually adequate to correct instabilities if encountered. Primary air preheating may be necessary to maintain flame

stability with coals of high ash content or mixture fuels of variable or low solids concentration (e.g., coal-water mixtures with less than 60 percent solids). Also, in some cases, an auxiliary startup fuel may be required.

Flame temperature and flame luminosity affect heat transfer as the combustion gases move through the combustion chamber (the furnace) and through the section containing convective heat transfer surfaces (the convection pass). Coal-oil mixtures burn with flame temperatures similar to those of burning oil; coal-water mixtures burn with significantly lower temperatures. The lower temperatures lead to reduced radiant heat transfer to the furnace water walls. Conversely, the luminosity of the coal mixture fuel flame is greater than that of either an oil or gas flame, leading to increased radiant heat transfer to the furnace wall tubes. Although these two opposing effects tend to cancel each other, significant performance degradation with coal mixture fuels can result (Reference 3-2).

Flames will be larger for mixture fuels than for oil because mixture fuel particles typically take longer to burn. Some effects of the larger flames and slower burning of mixture fuels are:

- Mixture fuel flames can impinge on the walls of furnaces of compact boilers designed for oil or gas, resulting in significant slag fouling.

- Furnace gas exit temperatures in a given boiler may be significantly higher with mixture fuels than with gas and oil. Although the mixture fuel flames are more luminous, with higher emitted radiant heat flux than flames from oil or gas, slag fouling of the furnace walls may reduce the rate of heat transfer to the water wall. Thus, less steam may be generated in the water wall surrounding the furnace, and more heat may be released in the convection pass.

If necessary, flame impingement and high furnace gas exit temperature can be corrected by reducing the firing rate (i.e., by derating) to achieve satisfactory boiler performance.

5.1.2 Effects of Ash

Ash in a coal mixture fuel has a major impact on the feasibility of conversion of boilers. The ash can cause fouling of the furnace walls and convection pass. It could also lead to significant erosion. Finally, provisions must be made to handle bottom ash and to capture and remove flyash.

Slag (molten ash) forms as the coal is burned. At low firing rates, depending on the ash fusion temperature, the slag may have time to solidify before impinging on the water walls. At higher firing rates, slag may form deposits on the water wall tubes and serve as a thermal barrier reducing heat transfer and steam generation in the water wall.

Ash carried along with the flue gas as particulate matter causes depositions in the convection sections of the boiler. If the ash has already cooled below its initial deformation temperature, depositions will be relatively loose and controllable by soot blowers. Boilers designed to burn No. 6 fuel oil frequently contain soot blowers in the convection pass. However, addition of soot blowers to retrofit certain compact boilers may require extensive rearrangement of convection tubes. If the ash impinges on convection tubes at temperatures above the initial deformation temperature, it will stick to the convection surface and resist removal by soot blowers. Accordingly, combustion chamber gas exit temperatures must be kept below ash initial deformation temperatures in retrofitted boilers. This may be accomplished by using coals with high ash fusion temperatures or reducing the firing rate, i.e., derating. Thus, the ash initial deformation temperature is a major parameter affecting the performance of a coal mixture fuel in a retrofitted boiler. To minimize derating in oil and gas-designed furnaces it is desirable to avoid coals with ash initial deformation temperatures below 2400°F.

The close tube spacing in oil- and gas-designed boilers produces higher flue gas velocities across the tubes, and higher rates of heat transfer. Design gas velocities in such boilers are typically 50 to 100 percent

higher than in boilers designed for coal. Velocities still higher will occur after retrofitting because of additional stoichiometric excess air required for burning coal. Plugging with closely spaced tubes could further aggravate the problem. At such high gas velocities, the entrained ash can cause severe erosion. The rate of erosion is a function of ash particle size, the quantity of ash present, and the velocity of the gas. Two counter measures can reduce erosion to tolerable levels without radical changes to the boiler:

- Reducing the quantity of ash (using clean coal)
- Reducing the firing rate to reduce gas velocity (i.e., by derating)

5.1.3 Effects of Equipment Type

The feasibility of retrofitting to coal mixture fuels will be affected significantly by boiler-related considerations such as:

- Fuels for which the boiler was originally designed
- Water tube vs. fire tube design
- Packaged vs. field erected design

Compared to boilers designed to accommodate coal, oil- or gas-designed boilers have:

- Smaller furnaces
- Closer tube spacing and higher gas velocities
- Finned tubes with closely spaced fins
- Often no provisions for ash removal
- Lower heat transfer in the radiant sections

Retrofit projects involve modifications of the boilers to adjust their configuration and operating parameters to satisfy characteristics of the new fuel.

Most large boilers are of water-tube design, in which the combustion gases flow outside the tubes, and water and steam flow inside the tubes.

In fire tube boilers, combustion gases flow inside the boiler tubes, and water and steam flow outside the tubes. Fire tube boilers are more common in low capacity units. To date, all experiments with coal mixture fuels appear to have been conducted in water tube boilers. One fire tube boiler manufacturer considers that design limitations would make it impractical to convert these boilers if they were designed exclusively for firing oil or gas. However, there are modern fire tube boilers, designed for use with coal. In these boilers, particulates are removed before the gases pass through the fire tubes. (Most coal-fired boilers for railroad locomotives are of fire-tube design; however, tube diameters are large, and the boilers do not meet efficiency requirements of modern heating plant boilers).

Industrial boilers can be of packaged or field erected design. Packaged units, common at lower capacities, are small enough to be transported completely assembled to the site. Erection is, in effect, performed in the factory. For field erected designs only components and subassemblies must be small enough to be transported. Boiler manufacturers expect that retrofitting field erected boilers to coal mixture fuels will prove more feasible than converting packaged boilers, because the packaged units tend to be more compact and contain less space to accommodate the increased flame size. Provisions for lowering convection section gas velocities and addition of ash handling facilities are also more feasible with field erected boilers.

5.1.4 Boiler Derating

From the foregoing discussion, it is evident that derating might be required to achieve satisfactory performance in some retrofitted boilers. The magnitude of the derating may range between 25 and 65 percent. Factors necessitating boiler derating with coal mixture fuels, discussed above, can be summarized as follows:

- When furnace size is too small and convection tube spacing is too close, derating is likely to be required. Most boilers designed for only oil or gas are in this category.

- To minimize the amount of derating required, coals used in mixture fuels for such boilers should have low ash content and a high ash fusion temperature.

- Boilers originally designed as coal capable will probably not require derating and restriction to clean coals with high ash fusion temperatures.

The required boiler derating must be determined by a detailed engineering study for each boiler and mixture fuel proposed. The appropriate derating for a boiler will be influenced by the following factors:

- Furnace volume, tube spacing, and equipment design at each point along the gas flow path

- Coal ash quantity and properties

- The extent of engineering changes considered economically and technically acceptable

- The amount of derating that is acceptable

Most Navy base boilers are for space heating purposes, and they will normally be called upon to operate at full capacity only a small fraction of the year during the coldest weather. Accordingly, either of the following retrofit strategies may be suitable for the Navy for a given boiler system:

- Strategy One - Recognize that severe convection tube erosion may occur only at the small fraction of the year during coldest weather. Accept the loss of equipment life due to burning mixture fuels at full rated capacity during short cold periods. An engineering study is required to establish the erosion expected in each heating season so that the boiler life and the feasibility of this strategy can be assessed.

- Strategy Two - Accept substantial derating in converted boilers while burning coal mixture fuels. Temporarily switch to oil or gas firing when steam delivery at rated capacity is required.

In most cases of retrofit of non-coal-capable boilers, there will be an engineering trade-off between the amount of derating accepted and the extent and cost of the retrofit equipment changes. Strategy Two may be an attractive method for minimizing both derating and retrofit requirements.

5.1.5 Feasibility Conclusions

The following general guidance may be helpful for preliminary assessment of the feasibility of retrofitting specific boilers in the absence of case-by-case modification studies:

- Coal-capable boilers are usually suitable for retrofitting.
- It may also be feasible to retrofit boilers that are not coal-capable. The difficulty of converting non-coal-capable boilers to coal mixture fuels appears to depend on boiler size and type in the following ways:
  - Small units may be more difficult to convert than larger units
  - Packaged units may be more difficult to convert than field erected units
  - Fire-tube boilers may be more difficult to convert than water-tube boilers

5.2 EQUIPMENT FOR UTILIZATION

The following discussion sets forth briefly the kind of boiler equipment changes required in a retrofit, the costs of a retrofit, and the emission control equipment required.

5.2.1 Retrofit Equipment Requirements

Conversion of a boiler to coal mixture fuels is likely to require addition of the following systems:

- Fuel handling and feed systems
- Special burners

- Soot blowers
- Ash drainage and removal systems

Boiler changes which may be required include:

- Rearrangement of baffles
- Relocation of some tube banks
- Increasing tube and fin spacing in some tube banks.

Changes in tube spacing are expensive, and they tend to reduce the boiler capacity when it is switched back to burning fuel oil or gas.

Appendix C contains a list of items which must be considered in analyses of the conversion of a boiler to coal or coal mixture fuels.

5.2.2 Particulate Emission Control Equipment

Particulate emission control equipment will be required for systems burning coal mixture fuels. Federal regulations for large sources limit particulate emissions to no more than 0.1 pound per 10^6 Btu of heat input. Either baghouses or electrostatic precipitators are required to meet these regulations when burning a coal fuel. Baghouse systems were described in Reference 1-5.

5.2.3 Sulfur Dioxide Emission Control Equipment

Sulfur dioxide emission control equipment may be required for systems burning coal mixture fuels. Since 1971, a limit of 1.2 pounds of sulfur dioxide (SO_2) per million Btu of fuel heat input was specified under federal regulations to industrial boilers designed for 250 x 10^6 Btu/hr or more of fuel heat input. Industrial boilers smaller than 250 x 10^6 Btu/hr, which include most boilers at Navy bases, are not currently subject to federal SO_2 emission regulations. The limit of 1.2 pounds of SO_2 per million Btu is a reasonable estimate of possible future federal requirements for small boilers. Under these limits, a coal

mixture fuel made with clean, low-sulfur coal may have sufficiently low emissions not to require SO_2 removal equipment. Sulfur dioxide removal system performance was discussed in Reference 1-6.

In this costing, no allowance has been made for additional equipment for NO_x control.

5.2.4 Cost of Conversion to Coal Mixture Fuels

The cost of converting a boiler plant to coal mixture fuels includes the costs of retrofitting the boilers, installation of particulate and SO_2 emission control equipment, and any neccessary control systems.

Estimates of boiler retrofit costs have been prepared by Bechtel recently for several industrial boilers. The results ranged between 7 and 14 percent of the costs of new coal-fired boilers of comparable size. On the basis of the above results, retrofit costs in this study have been taken as 10 percent of the cost of a new coal-fired boiler. Operating and maintenance labor and material costs for retrofitted boilers are assumed to be the same as those for a new stoker boiler of the same size.

Costs for baghouse particulate removal systems are given in Appendix D of Reference 1-6 and in Table A-4 of this report. Costs for sulfur dioxide emission control systems are given in Reference 1-6 and in Tables A-5 to A-8 of this report.

Section 6

COAL MIXTURE FUEL PREPARATION AND UTILIZATION IN 400,000 LB/HR CENTRAL STEAM PLANTS

This section presents flows and costs for preparation and utilization of coal mixture fuels in a representative central steam plant with a design capacity of 400,000 pounds per hour and operating at 50 percent load factor. Information is presented for coal-oil and coal-water mixture systems.

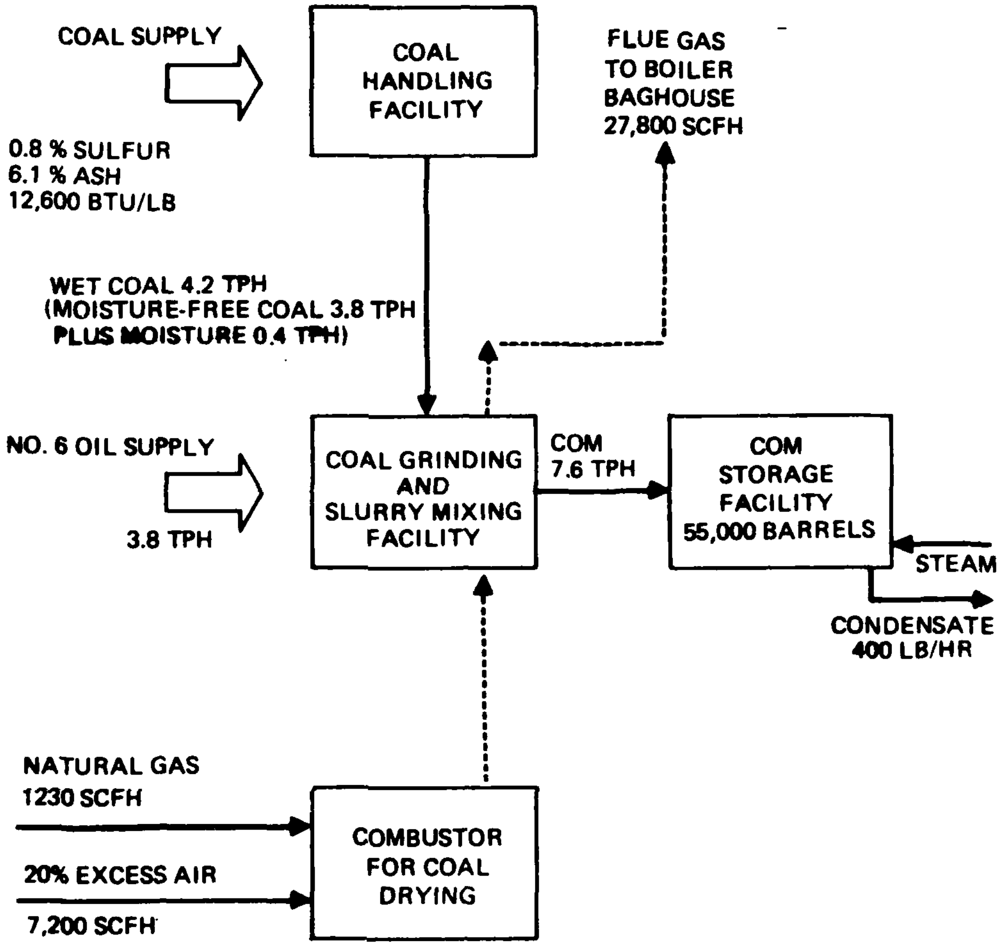
6.1 COAL-OIL MIXTURE SYSTEM FLOWS

6.1.1 Coal-Oil Mixture Preparation Facility

Figure 6-1 is a block flow diagram for a plant to produce a coal-oil mixture at a nominal rate of 7.6 tons per hour, the average rate required to supply a 400,000 pounds per hour central steam plant operating at an annual load factor of 50 percent. The diagram includes coal handling facilities, coal grinding and coal-oil slurry mixing facilities, a coal-oil mixture storage facility, and a combustor to supply hot gases for coal drying. The coal used is a low ash, low sulfur coal.

6.1.2 Coal-Oil Mixture Utilization

Figure 6-2 is a block flow diagram for a 400,000 pounds per hour central steam plant operating at its design capacity. At design capacity, the steam plant consumes coal-oil mixture at a rate of 15.2 tons per hour. This rate is higher than the rate of manufacture, and the additional required fuel is supplied from storage. Figure 6-2 includes the retrofitted boilers and bag filters for particulate pollution control. Less than 1.2 pounds of sulfur dioxide is produced per million Btu of fuel, so no sulfur dioxide pollution control is needed.



LEGEND:

COM: COAL-OIL MIXTURE
TPH: SHORT TONS PER HOUR
SCFH: STANDARD CUBIC FEET PER HOUR

Figure 6-1 BLOCK FLOW DIAGRAM: COAL-OIL MIXTURE PREPARATION TO SERVE 400,000 LB/HR BOILER PLANT OPERATING AT 50 PERCENT LOAD FACTOR

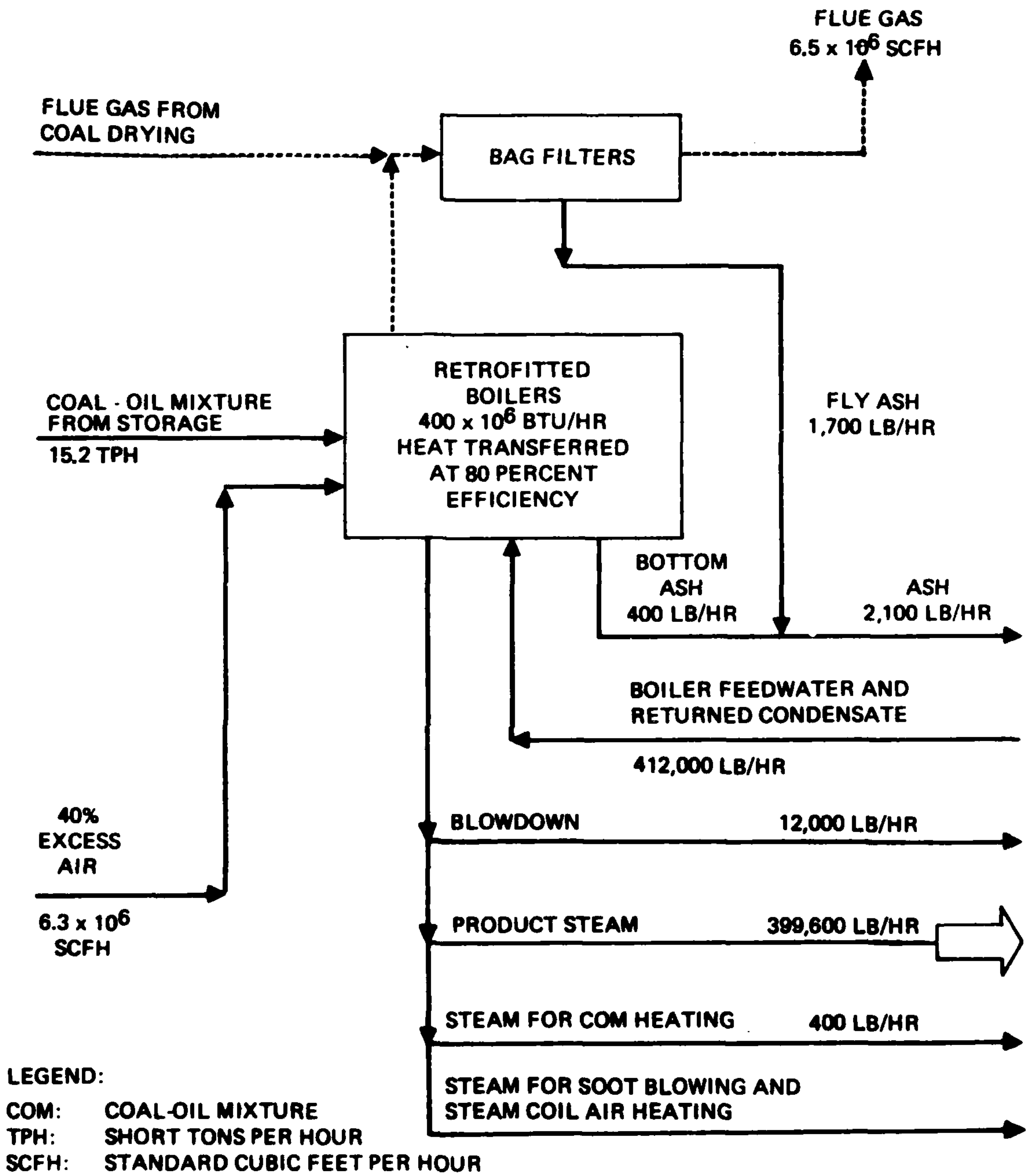


Figure 6-2 BLOCK FLOW DIAGRAM: COAL-OIL MIXTURE CONSUMPTION IN 400,000 LB/HR CENTRAL STEAM PLANT OPERATING AT DESIGN CAPACITY

6.2 COAL-WATER MIXTURE SYSTEM FLOWS

6.2.1 Coal-Water Mixture Preparation

Figure 6-3 is a block flow diagram for a plant to produce a coal-water mixture at a nominal rate of 22.2 tons per hour, the average rate required to supply a 400,000 pounds per hour central steam plant operating at an annual load factor of 50 percent. The diagram includes coal handling facilities, a coal grinding and coal-water slurry mixing facility, and a coal-water mixture storage facility. The coal used is a high ash, high sulfur coal.

6.2.2 Coal-Water Mixture Utilization

Figure 6-4 is a block diagram for a 400,000 pounds per hour central steam plant operating at its design capacity. At design capcity, the steam plant consumes coal-water mixture at a rate of 44.4 tons per hour. This rate is higher than the rate of manufacture, and the additional required fuel is supplied from storage. Figure 6-4 includes retrofitted boilers, bag filters for particulate pollution control, and double alkali scrubbers for sulfur dioxide pollution control.

6.3 COST COMPARISONS AND CONCLUSIONS

6.3.1 Cost Comparisons

Table 6-1 compares capital, annual, and life cycle levelized costs for six systems with the same capacity and load factor. The six systems are:

- Oil burned in existing boilers
- Coal-oil mixture made from low sulfur coal, burned in retrofitted boiler plant (the system of Figure 6-1 and 6-2)
- Coal-water mixture made from low sulfur coal, burned in retrofitted boiler plants
- New direct coal-fired stoker boiler plant burning low sulfur coal

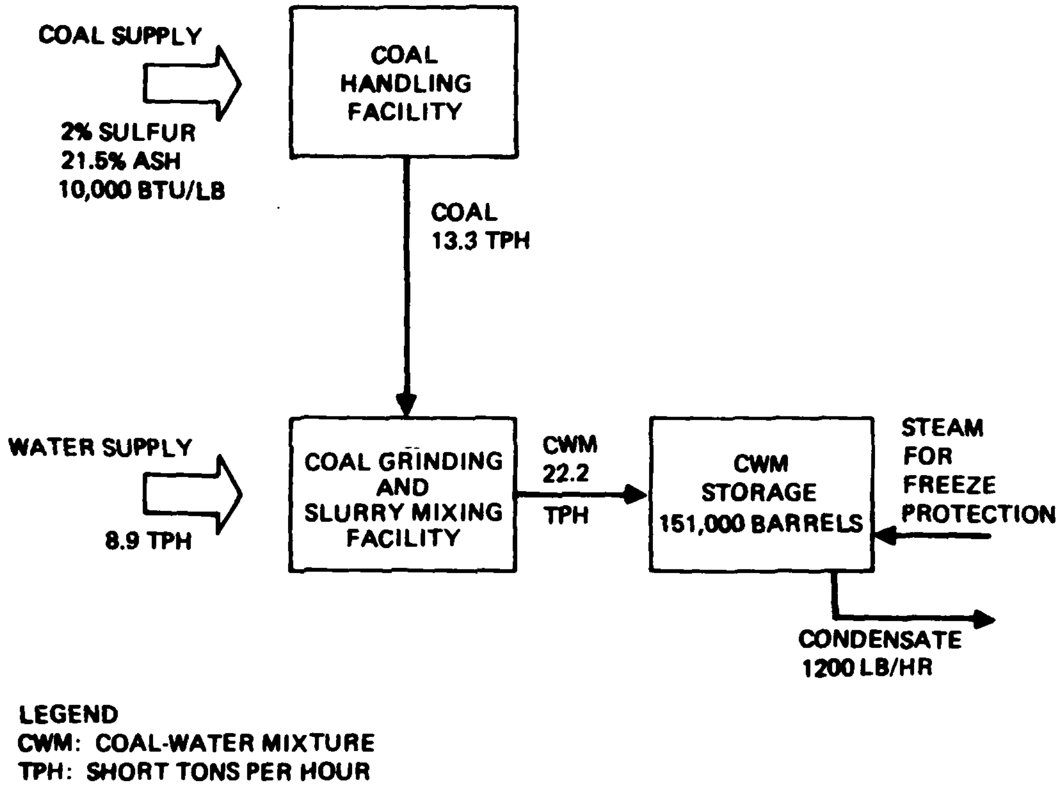


Figure 6-3 BLOCK FLOW DIAGRAM: COAL-WATER MIXTURE PREPARATION TO SERVE 400,000 LB/HR BOILER PLANT OPERATING AT 50 PERCENT LOAD FACTOR

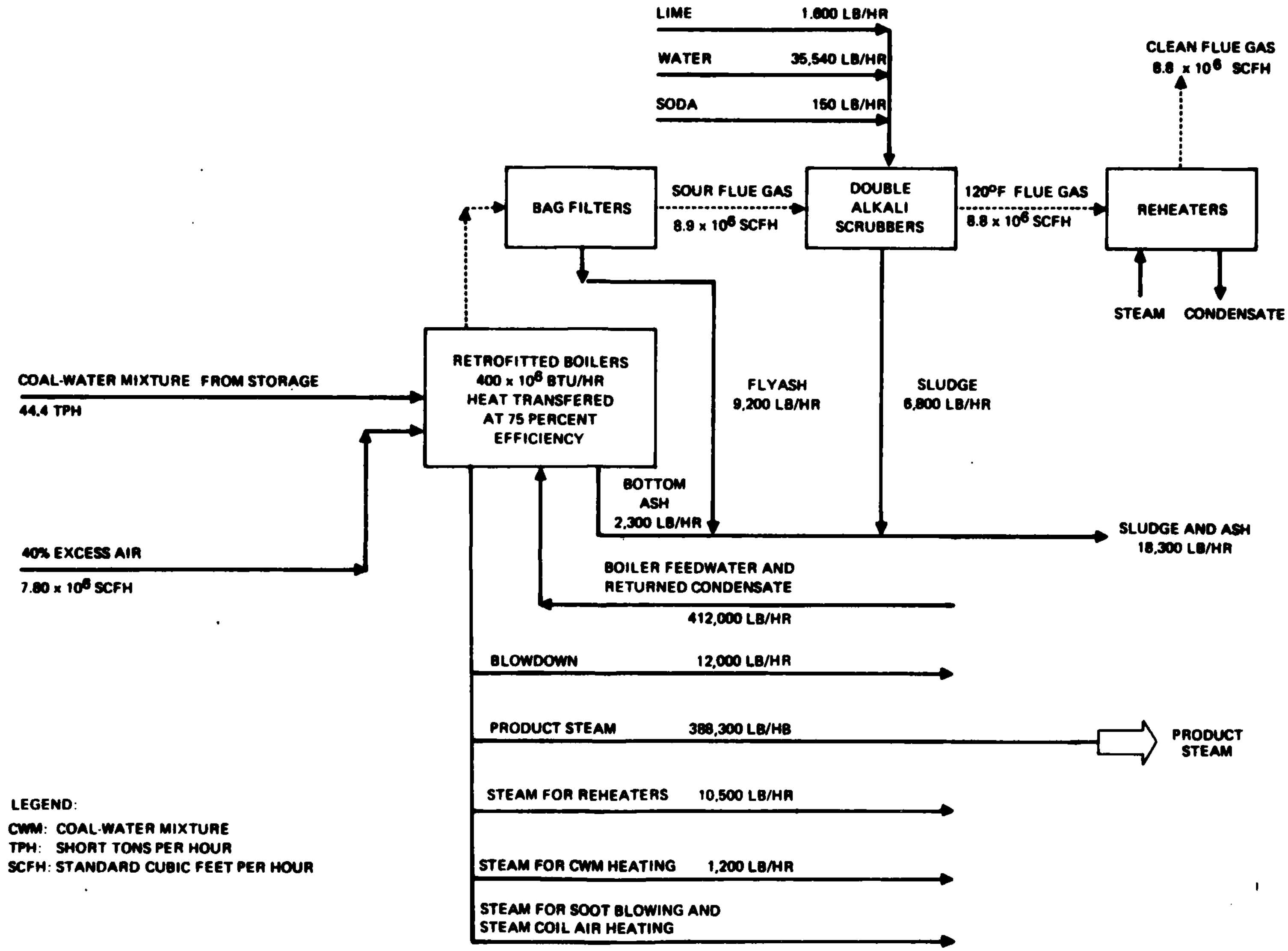


Figure 6-4 BLOCK FLOW DIAGRAM: COAL-WATER MIXTURE CONSUMPTION IN 400,000 LB/HR CENTRAL STEAM PLANT OPERATING AT DESIGN CAPACITY

Table 6-1

COMPARATIVE COSTS OF STEAM FOR COAL MIXTURE FUELS
IN 400,000 LB/HR CENTRAL STEAM PLANTS
OPERATING AT 50 PERCENT LOAD FACTOR
(Navy Economic Assumptions)

Item	Units	Oil in Existing Boilers	Low Sulfur Coal: Coal-Oil Mixtures in Retrofitted Boilers	Low Sulfur Coal: Coal-Water Mixtures in Retrofitted Boilers	Low Sulfur Coal: Coal in New Stoker Boilers	High Sulfur Coal: Coal-Water Mixtures in Retrofitted Boilers	High Sulfur Coal: Coal in New Stoker Boilers
Capital Cost(1)							
Coal Handling	10^3 $	0	2,164	6,267	5,674	6,267	5,674
Grinding, Mixing	10^3 $	0	2,636	2,405	0	2,405	0
Slurry Storage	10^3 $	0	764	1,867	0	1,867	0
Boilers, Retrofit or new	10^3 $	0	1,873	1,873	18,731	1,873	18,731
Particulate Control	10^3 $	0	4,193	4,193	4,193	4,193	4,193
Sulfur Dioxide Control	10^3 $	0	0	0	0	8,049	8,049
Total Construction Cost	10^3 $	0	11,630	16,605	28,598	24,654	36,647
Startup Cost	10^3 $	0	1,279	1,827	3,174	2,712	4,031
Total Capital Cost	10^3 $	0	12,909	18,432	31,772	27,366	40,678
Round Off to			12,900	18,400	31,800	27,400	40,700
First Year Operating and Maintenance Cost(1)							
Labor	10^3 $/yr	584	2,419	2,564	2,023	3,302	2,761
Materials	10^3 $/yr	173	892	1,117	884	1,765	1,523
Water	10^3 $/yr	1	1	10	1	19	9
Electricity	10^3 $/yr	137	371	441	343	551	447
Natural Gas	10^3 $/yr	0	48	0	0	0	0
Steam	10^3 $/yr	0	27	78	0	406	308
Oil	10^3 $/yr	15,884	9,168	0	0	0	0
Coal	10^3 $/yr	0	2,356	5,887	5,519	5,887	5,519
Total First Year Cost	10^3 $/yr	16,779	15,282	10,097	8,770	11,930	10,558
Round Off to		16,800	15,300	10,100	8,800	11,900	10,600
Life Cycle Levelized Cost of Steam(2)							
Investment	$/$10^3$ lb	0.00	0.84	1.20	2.07	1.78	2.64
Oil	$/$10^3$ lb	28.05	16.19	0.00	0.00	0.00	0.00
Coal	$/$10^3$ lb	0.00	2.66	6.65	6.24	6.65	6.24
Other Annual	$/$10^3$ lb	0.77	2.53	2.70	2.06	4.15	3.44
Total Levelized Cost	$/$10^3$ lb	28.84	22.22	10.55	10.37	12.58	12.32
Round Off to		28.80	22.20	10.60	10.40	12.60	12.30

(1) The capital and annual costs are in fourth quarter 1982 dollars.
(2) The life cycle costs are fourth quarter 1982 constant dollar unit levelized costs derived from present values for plants starting up in November 1987 and operating for 25 years. Differential inflation of energy costs over the operating life has been taken into account.

- Coal-water mixture made from high sulfur coal, burned in retrofitted boiler plant with new sulfur dioxide control units (the system of Figures 6-3 and 6-4)

- New direct coal-fired stoker boiler plant burning high sulfur coal and including new sulfur dioxide control units

The costs for coal mixture fuel preparation facilities in Table 6-1 are taken from the parametric cost-versus-capacity tables in Section 4 of this report. The capital cost for retrofitting an existing boiler to firing coal mixture fuel is taken to be 10 percent of the cost of a new stoker boiler of the same capacity, as explained in Section 5.2.4. Costs for for pollution control systems and for the direct coal-fired stoker boiler system are taken from References 1-5 and 1-6. The costs for burning oil in existing boilers are derived from Reference 1-9.

Capital costs in Table 6-1 include costs for coal handling, coal grinding and slurry mixing, slurry storage, boilers, particulate pollution control, sulfur dioxide control, and startup.

It has been assumed that existing oil-fired boilers are relatively new, so that no capital expenditure is required to continue burning oil in the existing boiler. Table 6-1 shows that capital costs for coal mixture fuel systems are significantly lower than those for a new coal-fired stoker boiler system.

Annual costs in Table 6-1 include costs for labor, materials, water, electricity, auxiliary natural gas, auxiliary steam, oil and coal. The cost of oil is seen to dominate the annual costs in Table 6-1.

The life cycle costs in Table 6-1 are constant dollar levelized costs calculated using the Navy economics methodology.

Cost assumptions used in deriving Table 6-1 are summarized in Tables 6-2, 6-3, and 6-4.

Table 6-2

COST ESCALATION ASSUMPTIONS

Method of Cost Escalation

Use of cost index published by Chemical Engineering magazine

Cost Items Affected

- Construction costs
- Startup costs
- Materials costs for annual operation and maintenance

Formation of Adjustment Multiplier to Escalate Cost Items to Fourth Quarter (November) 1982 Dollars

Date of Original Estimate	Plant Module	Cost Index	Adjustment Multiplier
February 1978	Coal handling, boilers, baghouses, scrubbers	216.8	315.0/216.8
November 1982	Coal grinding and slurry mixing, slurry storage	315.0	315.0/315.0

Table 6-3

ENERGY AND LABOR COST ASSUMPTIONS

Cost Item	Price Units	Delivered Price[1]	$\$/10^6$ Btu
High Ash Coal (10,000 Btu/lb as received) for coal-water mixture, direct-fired stokers	$/ton	50.40	2.52[2]
Low Ash Coal (12,600 Btu/lb as received)	$/ton	63.50	2.52[2]
Oil (18,800 Btu/lb)	$/gal	1.088	7.30
Natural Gas	$ per thousand standard cubic feet	4.64	4.64
Steam	$ per thousand pounds	7.25	7.25
Electricity	$/kWh	0.0604	Not applicable
Labor (including benefits and supervision	$ per manhour	30.00	Not applicable

(1) All prices are in fourth quarter (November) 1982 dollars. Energy prices are average prices paid by the Navy in November 1982.

(2) Although in the 1978 coal market of the Reference 1-9 study, cleaned coals commanded a dollars-per-million Btu price differential which covered the added costs of coal cleaning, in the current market cleaned coals are not able to command such a price differential compared to ordinary Eastern coal. In the future, the coal market may become more firm, and cleaned coal may command a price differential again.

Table 6-4

LIFE CYCLE COST ASSUMPTIONS

Capital Spending Assumptions

- Startup in November 1987
- Two-year construction period
- Expenditure of 37 percent of construction cost in first construction year
- Expenditure of 63 percent of construction cost in second construction year
- Expenditure of startup costs (owner's costs) in second construction year

Operating Cost Assumptions

- 25-year plant operating life
- Differential inflation of purchased energy compared to general inflation (values taken from Reference 1-8):

Energy Commodity	Differential Inflation Rate (percent/year)
Coal	5
Electricity	6
Steam	6
Oil	8
Natural Gas	10

Navy Economic Analysis Assumptions

- Constant dollar analysis with zero percent general inflation
- 10 percent per year constant dollar discount rate for calculation of present values and levelized costs

6.3.2 Conclusions About Coal Mixture Fuel Economics

The comparisons lead to the following conclusions about the economics of coal mixture fuel technologies:

- Burning coal-oil mixtures in retrofitted coal-capable boilers results in life cycle costs close to the cost of burning oil in existing boilers, and significantly higher than costs for burning coal in new stoker boilers.

- Burning coal-water mixtures in retrofitted coal-capable boilers results in life cycle costs comparable with the costs for burning coal in new stoker boilers.

REFERENCES

1-1 Economic Analysis Handbook, P-422, Naval Facilities Engineering Command, 1975.

1-2 Slaminski, J. M., "Economic Analysis and Priority Rating Formulation for Navy Shore Facilities Energy R&D Projects," Civil Engineering Laboratory, Naval Construction Battalion Center, Port Hueneme, California, November 1977.

1-3 Instruction for Preparation of Economic Analyses, LANTNAVFACENGCOM, 407:ARM, March 19, 1980.

1-4 Ward, Carter J., "Simplified Economic Analysis for Navy Shore Facilities Energy R&D Products," Civil Engineering Laboratory, Naval Construction Battalion Center, Port Hueneme, California, December 1979.

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1-6 Flue Gas Desulfurization at Navy Bases, Bechtel National, Inc., San Francisco, California, CEL Contract Report CR 80.023, Navy Energy Guidance Study, Phase IV, August 1980.

1-7 Coal Conversion Cost Computer Program, Peter F. Loftus Corporation, Pittsburgh, Pennsylvania, Draft NCEL Contract Report, Contract N62474-81-C-9409, September 1982.

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1-9 Coal Energy Conversion Options for Navy Bases, Bechtel National, Inc., San Francisco, California, CEL Contract Report CR 79.005, March 1979.

3-1 COALM - Coal Conversion Cost Program with Mixture Fuels: User Manual, Bechtel Group, Inc., San Francisco, California, Draft NCEL Contract Report, Contract N62474-82-C-8290, September 1983.

3-2 Coal-Oil Mixture as a Utility Boiler Fuel, Volume 1: Conversion Guidelines Handbook, Bechtel Group, Inc., San Francisco, California, Final Report CS-2309, Volume 1, Research Project 1455-2, Electric Power Research Institute, Palo Alto, California, March 1982.

APPENDIX A

DECEMBER 1982 UPDATE OF PERFORMANCE AND COST DATA FOR COAL FIRED BOILER INSTALLATIONS WITH POLLUTION CONTROL

Appendix A

LIST OF TABLES

Appendix A

DECEMBER 1982 UPDATE OF PERFORMANCE AND COST DATA FOR COAL FIRED BOILER INSTALLATIONS WITH POLLUTION CONTROL

This appendix contains a December 1982 update of selected data which appeared in References 1-5 and 1-6.

These documents serve as a data base for the Reference 1-7 computer program, which has been incorporated into the Phase II computer program under the present contract.

The December 1982 update was carried out to bring the data base to a definitive form to be used in conjunction with added data on coal mixture fuels under the present contract.

The update activity was occasioned principally by a requirement to bring pollution control annual costs into conformity with Appendix D of Reference 1-6. Also, selected costs and performance factors from References 1-5 and 1-6 were recalculated. Tables A-1 to A-10 present the updated information.

Table A-1

TOTAL CONSTRUCTION COSTS FOR SODA LIQUOR FLUE GAS DESULFURIZATION SYSTEMS THAT PRODUCE LIQUID WASTE, FOR SINGLE DECENTRALIZED BOILERS (1), (2)

Coal % S	Boiler Capacity, 10^6 Btu/hr Heat Transferred	Thousands of Dollars (3)		
		Equipment and Materials	Labor	Total Construction Cost
2	25	225	190	415
2	50	275	255	530
2	100	405	375	780
2	200	675	615	1290
4	25	240	225	465
4	50	360	320	680
4	100	630	550	1180
4	200	995	895	1890

(1) This table is a December 1982 supplement to Table D-1 of CEL Contract Report CR 80.023, "Flue Gas Desulfurization at Navy Bases, Navy Energy Guidance Study, Phase IV, August 1980. Table D-1 gives total construction costs for flue gas desulfurization systems that produce solid waste. This table gives the total construction costs for a soda liquor system that produces liquid waste.

(2) For each boiler, one flue gas desulfurization system is provided, which is capable of processing 100 percent of boiler flue gas output.

(3) Costs are in second quarter 1978 dollars.

Table A-2

TOTAL CONSTRUCTION COSTS FOR SODA LIQUOR FLUE GAS DESULFURIZATION SYSTEMS THAT PRODUCE LIQUID WASTE, FOR CENTRAL BOILER PLANTS (1), (2)

Coal % S	Boiler Plant Capacity, 10^6 Btu/hr Heat Transferred	Thousands of Dollars (3)		
		Equipment and Materials	Labor	Total Construction Cost
2	100	540	485	1025
2	200	855	795	1650
2	400	1500	1350	2850
2	800	2265	2085	4350
4	100	700	625	1325
4	200	1095	1005	2100
4	400	1740	1560	3300
4	800	2875	2575	5450

(1) This table is a December 1982 supplement to Table D-2 of CEL Contract Report CR 80.023, "Flue Gas Desulfurization at Navy Bases, Navy Energy Guidance Study, Phase IV," August 1980. Table D-1 gives total construction costs for flue gas desulfurization systems that produce solid waste. This table gives the total construction costs for a soda liquor system that produces liquid waste.

(2) The flue gas desulfurization consists of two trains, each capable of processing 60 percent of the boiler plant flue gas output.

(3) Costs are in second quarter 1978 dollars.

Table A-3

ANNUAL OPERATING AND MAINTENANCE COSTS, DECENTRALIZED AND CENTRAL BOILER PLANTS (1)

Type of Plant	Plant Capacity 10^6 Btu/hr Heat Transferred	Thousands of Dollars (2)		
		Material	Labor	Annual O&M (3)
Single	25	32	120	152
Decentralized	50	53	185	238
Boilers	100	88	316	404
	200	146	514	660
Central Plants	100	112	370	482
with Four	200	186	558	744
Quarter-Size	400	310	936	1246
Boilers	800	527	1602	2129

(1) This table is a December 1982 update of Table 4-5 in CEL Contract Report 79.012, "Coal Fired Boilers at Navy Bases, Navy Energy Guidance Study, Phases II and III," May 1979.

(2) Costs are in second quarter 1978 dollars.

(3) This total does not include the cost of electricity and water consumed by the boilers.

Table A-4

ANNUAL OPERATING AND MAINTENANCE COSTS FOR BAGHOUSE PARTICULATE REMOVAL SYSTEMS FOR DECENTRALIZED AND CENTRAL BOILER PLANTS (1)

Type of Plant	Plant Capacity, 10^6 Btu/hr Heat Transferred	Thousands of Dollars (2)		
		Material	Labor	Total Annual O&M
Single Decentralized Boilers (3)	25	14	23	37
	50	20	25	45
	100	33	28	61
	200	52	32	84
Central Plants (4)	100	46	90	136
	200	67	95	162
	400	96	102	198
	800	163	119	312

(1) This table provides a December 1982 update of the low sulfur coal information provided in Tables 5-7 and 5-8 of CEL Contract Report CR 79.012, "Coal Fired Boilers at Navy Bases, Navy Energy Guidance Study, Phases II and III," May 1979. This table is based on tables in Appendix D of CEL Contract Report CR 80.023, "Flue Gas Desulfurization at Navy Bases, Navy Energy Guidance Study, Phase IV," August 1980.

(2) Costs are in second quarter 1978 dollars.

(3) For each decentralized boiler, a single baghouse system is provided, which is capable of processing 100 percent of the boiler flue gas output.

(4) For central plants, the baghouse system consists of two trains, each capable of processing 60 percent of the boiler plant flue gas output.

Table A-5

ANNUAL COSTS FOR OPERATING AND MAINTENANCE LABOR, LABOR-RELATED OPERATING SUPPLIES, AND MAINTENANCE MATERIALS FOR FLUE GAS DESULFURIZATION SYSTEMS THAT PRODUCE SOLID WASTE, FOR SINGLE DECENTRALIZED BOILERS (1)

Coal % S	Boiler Capacity, 10^6 Btu/hr Heat Transferred	Thousands of Dollars (2)			
		Operating Labor (3)	Maintenance Labor (4)	Operating Supplies (5)	Maintenance Materials (6)
2	25	194	17	16	33
2	50	220	21	18	42
2	100	246	31	20	62
2	200	272	52	22	104
4	25	194	19	16	37
4	50	220	27	18	54
4	100	246	47	20	94
4	200	272	76	22	152

(1) This table provides a December 1982 update of medium and high sulfur coal information provided in Table 5-7 of CEL Contract Report CR 79.012, "Coal Fired Boilers at Navy Bases, Navy Energy Guidance Study, Phases II and III," May 1979. It is based on CEL Contract Report CR 80.023, "Flue Gas Desulfurization at Navy Bases, Navy Energy Guidance Study, Phase IV," August 1980.

(2) Costs are in second quarter 1978 dollars.

(3) Operating labor is based on Tables 4-3 to 4-5 of CR 80.023, with linear extrapolation.

(4) Maintenance labor is 2 percent of total construction cost in Table D-1 of CR 80.023.

(5) Operating supplies are 8 percent of operating labor.

(6) Maintenance materials are 4 percent of total construction cost in Table D-1 of CR 80.023.

Table A-6

ANNUAL COSTS FOR OPERATING AND MAINTENANCE LABOR, LABOR-RELATED OPERATING SUPPLIES, AND MAINTENANCE MATERIALS FOR FLUE GAS DESULFURIZATION SYSTEMS THAT PRODUCE SOLID WASTE, FOR CENTRAL BOILER PLANTS (1)

Coal % S	Combined Plant Capacity, 10^6 Btu/hr Heat Transferred	Thousands of Dollars (2)			
		Operating Labor (3)	Maintenance Labor (4)	Operating Supplies (5)	Maintenance Materials (6)
2	100	260	41	21	82
2	200	320	66	26	132
2	400	380	114	30	228
2	800	440	174	35	348
4	100	260	53	21	106
4	200	320	84	26	168
4	400	380	132	30	264
4	800	440	218	35	436

(1) This table provides a December 1982 update of medium and high sulfur coal information provided in Table 5-8 of CEL Contract Report CR 79.012, "Coal Fired Boilers at Navy Bases, Navy Energy Guidance Study, Phases II and III," May 1979. It is based on CEL Contract Report CR 80.023, "Flue Gas Desulfurization at Navy Bases, Navy Energy Guidance Study, Phase IV," August 1980.

(2) Costs are in second quarter 1978 dollars.

(3) Operating labor is based on Tables 4-1 and 4-2 of CR 80.023, with linear extrapolation.

(4) Maintenance labor is 2 percent of total construction cost in Table D-2 of CR 80.023.

(5) Operating supplies are 8 percent of operating labor.

(6) Maintenance materials are 4 percent of total construction cost in Table D-2 of CR 80.023.

Table A-7

ANNUAL COSTS FOR OPERATING AND MAINTENANCE LABOR, LABOR-RELATED OPERATING SUPPLIES, AND MAINTENANCE MATERIALS FOR A SODA LIQUOR FLUE GAS DESULFURIZATION SYSTEM THAT PRODUCES LIQUID WASTE, FOR SINGLE DECENTRALIZED BOILERS (1)

Coal % S	Boiler Capacity, 10^6 Btu/hr Heat Transferred	Thousands of Dollars (2)			
		Operating Labor (3)	Maintenance Labor (4)	Operating Supplies (5)	Maintenance Materials (6)
2	25	180	9	14	17
2	50	200	11	16	21
2	100	220	16	18	31
2	200	240	26	19	52
4	25	180	10	14	19
4	50	200	14	16	27
4	100	220	24	18	47
4	200	240	38	19	76

(1) This table provides a December 1982 update of medium and high sulfur coal information provided in Table 5-7 of CEL Contract Report CR 79.012, "Coal Fired Boilers at Navy Bases, Navy Energy Guidance Study, Phases II and III," May 1979. It is based on CEL Contract Report CR 80.023, "Flue Gas Desulfurization at Navy Bases, Navy Energy Guidance Study, Phase IV," August 1980.

(2) Costs are in second quarter 1978 dollars.

(3) Operating labor is based on Tables 4-3 to 4-5 of CR 80.023, with linear extrapolation.

(4) Maintenance labor is 2 percent of the total construction cost in Table A-1 of this appendix.

(5) Operating supplies are 8 percent of operating labor.

(6) Maintenance materials are 4 percent of the total construction cost in Table A-1 of this appendix.

Table A-8

ANNUAL COSTS FOR OPERATING AND MAINTENANCE LABOR, LABOR-RELATED OPERATING SUPPLIES, AND MAINTENANCE MATERIALS FOR A SODA LIQUOR FLUE GAS DESULFURIZATION SYSTEM THAT PRODUCES LIQUID WASTE, FOR CENTRAL BOILER PLANTS

Coal % S	Combined Plant Capacity, 10^6 Btu/hr Heat Transferred	Thousands of Dollars (2)			
		Operating Labor (3)	Maintenance Labor (4)	Operating Supplies (5)	Maintenance Materials (6)
2	100	230	21	18	41
2	200	260	33	21	66
2	400	290	57	23	114
2	800	320	87	26	174
4	100	230	27	18	53
4	200	260	42	21	84
4	400	290	66	23	132
4	800	320	109	26	218

(1) This table provides a December 1982 update of medium and high sulfur coal information provided in Table 5-8 of CEL Contract Report CR 79.012, "Coal Fired Boilers at Navy Bases, Navy Energy Guidance Study, Phases II and III," May 1979. It is based on CEL Contract Report CR 80.023, "Flue Gas Desulfurization at Navy Bases, Navy Energy Guidance Study, Phase IV," August 1980.

(2) Costs are in second quarter 1978 dollars.

(3) Operating labor is based on Tables 4-1 and 4-2 of CR 80.023, with linear extrapolation.

(4) Maintenance labor is 2 percent of the total construction cost in Table A-2 of this appendix.

(5) Operating supplies are 8 percent of operating labor.

(6) Maintenance materials are 4 percent of the total construction cost in Table A-2 of this appendix.

Table A-9

DESIGN POWER REQUIREMENTS
FOR LOW PRESSURE STOKER
AND PULVERIZED COAL BOILERS

Item	Units	Amount
Boiler Heat Transferred	10^6 Btu Transferred Per Hour	200
Boiler Fuel Consumption	10^6 Btu Fuel Per Hour	250
Power Demand	Kilowatts	600 (1)

(1) This power demand has been calculated during the 1982 data base update.

Table A-10

ANNUAL FLOWS OF RAW MATERIALS, UTILITIES, BY-PRODUCTS, AND WASTES FOR COMMERCIAL FLUE GAS DESULFURIZATION (FGD) TECHNOLOGIES (1), (2)

Technology	Limestone Slurry	Lime Slurry	Double Alkali	Soda Liquor Solid Waste	Soda Liquor Liquid Waste	Wellman - Lord/Allied Chemcial
Lime, tons/yr	910	8,510	7,330			
Limestone, tons/yr	14,630					
Soda Ash, tons/yr			670	11,210	11,210	550
Water, 10^3 gal/yr	19,500	19,200	18,500	18,400	24,730	414,400 (3)
Steam, 10^3 lb/yr	42,500	42,500	42,500	42,500	42,500	123,800
Electricity, MWhr/yr	4,870	4,220	2,010	4,910	2,010	4,240
Scrubber Waste, tons/yr (4)	38,600	34,800	31,800	29,600	56,050	710
Natural Gas, 10^3 scf/yr						42,300
Elemental Sulfur, tons/yr						3,200

(1) This table is a December 1982 update of Table 3-1 of CEL Contract Report CR 80.023, "Flue Gas Desulfurization at Navy Bases, Navy Energy Guidance Study Phases II and III," August 1980.

(2) The table is based on combustion of 111,055 short tons per year of a Macoupin County Illinois Number 6 Coal with a higher heating value of 9860 Btu per pound and containing the following composition percentages: sulfur 3.39, moisture 12.58, ash 16.50, carbon 53.81 hydrogen 4.00, nitrogen 1.08, oxygen 8.64. The flows have been computed assuming 90 percent removal of input fuel sulfur, in conformity with the New Source Performance Standards promulgated by the Environmental Protection Agency in June 1979. Under this assumption, 3388 short tons of sulfur per year are removed by the FGD systems. Combined excess combustion air and in-leakage before entry to the scrubber is 60 percent of stoichiometric air. 3 percent of the coal carbon leaves unburned with the ash. Char plus fly

Table A-10 (Continued)

ash streams total 20,100 tons per year. These flows are expected for a steam plant with an output of 400 million Btu per hour operating at 50 percent load factor. Many entries in this table have been rounded off.

(3) Wellman-Lord water requirments include 401,666 x 10^3 gal/yr of cooling water, 11,439 x 10^3 gal/yr of process makeup water, and 1,257 x 10^3 gal/yr of boiler feed water.

(4) Tonnages refer to sludge containing 50 percent solids for limestone slurry, lime slurry, and double alkali processes, refer to drained crystals containing approximately 50 percent water of hydration for the soda liquor solid waste and Wellman-Lord processes, and refer to a solution containing 25 percent dissolved salts for the soda liquor process with liquid waste.

APPENDIX B

JULY 1983 UPDATE OF PERFORMANCE
DATA FOR COGENERATION SYSTEMS

Appendix B

LIST OF TABLES

Appendix B

JULY 1983 UPDATE OF PERFORMANCE DATA FOR COGENERATION SYSTEMS

This appendix contains a July 1983 update of selected data which appeared in References 1-5. This document forms the principal part of the data base for the Reference 1-7 computer program, which has been incorporated into the Phase II computer program under the present contract. The July 1983 update was carried out to bring the data base into definitive form to be used in verification of cogeneration features of the Phase II computer program.

Table B-1

ANNUAL AVERAGE STEAM FLOWS AND POWER GENERATED IN A 400,000 LB/HR COGENERATION PLANT OPERATING AT 33 PERCENT HEATING SYSTEM LOAD FACTOR, WITH CONDENSING GENERATION FOR PEAK SHAVING[1]

Type of Flow	$\left(\dfrac{\text{Average Steam Flow for Type}}{\text{Maximum Steam Flow for Type}}\right)$	Average Steam Flow, lb/hr	Average Electricity Production, MWe
Steam Extracted	0.60	110,000	6.36
Steam to Condensing Section for Peak Shaving	0.04	3,200	0.41
Steam to Condensing Section for Turbine Cooling	0.96	8,700	0.60

(1) This table is a July 1983 supplement to information on page 9-12 of CEL Contract Report 79.012, "Coal Fired Boilers at Navy Bases, Navy Energy Guidance Study, Phases II and III, May, 1979.

Table B-2

ANNUAL UTILITIES FOR A 400,000 LB/HR COGENERATION PLANT OPERATING AT 33 PERCENT HEATING SYSTEM LOAD FACTOR, WITH CONDENSING GENERATION FOR PEAK SHAVING(1)

Module	Electricity, 10^3 KWh	Water 10^3 Gallon
Coal Preparation	350	-
L-P(2) Boilers	320	134
Scrubbers for L-P Boilers	120	780
H-P(3) Boilers	5,310	1,336
Scrubbers for H-P Boilers	1,700	10,750
Miscellaneous	200	18,700
Total	8,000	31,700

(1) This table is a July 1983 update of Table 9-4 of CEL Contract Report 79.012, "Coal Fired Boilers at Navy Bases, Navy Energy Guidance Study, Phases II and III, May, 1979.

(2) L-P indicates low pressure

(3) H-P indicates high pressure

(4) Annual average cogeneration cooling system requirements are 11,800 lb/hr for cooling tower evaporation and 6,000 lb/hr for blowdown and windage losses.

APPENDIX C

CHECKLIST OF QUESTIONS FOR CONVERSION OF GAS AND OIL-FIRED BOILERS TO FIRING COAL MIXTURE FUELS

Appendix C

CHECKLIST OF QUESTIONS FOR CONVERSION OF GAS AND OIL-FIRED BOILERS TO FIRING COAL MIXTURE FUELS

The following list of questions is intended to assist in establishing the scope of detailed engineering analysis of the feasibility of conversion of a boiler to a coal mixture fuel.

C.1 GENERAL FACILITY QUESTIONS

- Is there enough space for an on-base coal mixture fuel preparation plant? If not, is there at least enough space for a slurry receiving terminal?
- Is there enough space to accommodate coal mixture fuel storage facilities?
- Is there enough space for ash removal and storage facilities?
- Is there enough space near the boiler for particulate pollution control equipment?
- Is there enough space near the boiler for sulfur dioxide pollution control equipment and associated solid waste removal and storage facilities?
- What is the age and expected remaining life of each boiler?

C.2 FUEL RELATED QUESTIONS

- What is the composition of the coal?
- What is the composition of the ash?
- What are the values of the following ash fusion temperatures (under both reducing and oxidizing conditions)?
  - Initial deformation temperature
  - Softening temperature

- Hemispherical temperature

- Fluid temperature

C.3 FURNACE DESIGN QUESTIONS(1)

- What are the values of the following existing furnace design parameters?

  - Net heat input per unit plan area (Btu/ft^2)

  - Combustion rate (But/ft^3 of furnace)

  - Furnace release rate (Btu/ft^2 effective projected radiant surface)

  - Vertical height from top of fuel nozzle to furnace exit

C.4 BOILER DESIGN QUESTIONS

- Do burners need replacement or modifications and how much of a modification is required in the furnace walls to mount the new burners?

- Is there enough radiant surface to cool the combustion gases to below the ash fusion point at the furnace unit?

- Are there soot blowers, and if there are none, is there enough space to install new soot blowers?

- Do the first rows of tubes in the superheater banks have more than 6" clear space?

- Will the gas velocity in the convection pass be low enough to avoid erosion?

- Are the tubes in the economizers spaced far enough apart? Is the fin spacing appropriate?

- Will the air heater be capable of handling ash-laden gases without plugging?

- Can the forced draft and induced draft fans provide the air and gas flow at required capacity?

- Must the wind box be enlarged?

(1) The manufacturer of the boiler can determine these parameters from boiler design drawings and performance specifications.

- Can the attemperators handle the superheat excursions?
- Can furnace and convection pass tubes tolerate the corrosive properties of the ash?
- Does the boiler have a hopper in the bottom for ash removal? If not, how much excavation below grade is required to provide one?
- Can the boiler structure support the weight of additional equipment?

COMPUTER PROGRAM
USER MANUAL

COALM -
COAL CONVERSION COST PROGRAM
WITH MIXTURE FUELS

CONTENTS

TABLES

ILLUSTRATIONS

Section 1

PROGRAM CAPABILITY

1.1 PROGRAM DESCRIPTION AND GENERAL APPROACH

COALM - Coal Conversion Cost Program with Mixture Fuels - is a computer program prepared for the Naval Civil Engineering Laboratory, Port Hueneme, California, by Bechtel Group, Inc., as part of the work of Phase II of "Engineering Services for Coal Conversion Guidance," Navy Contract N62474-82-C-8290. COALM includes data prepared for NCEL in previous studies and new data generated in the Phase II work. COALM was constructed by adapting an existing NCEL program.

COALM calculates flows and costs of coal fired steam and power generation facilities for Navy bases of arbitrary configuration, building total costs from the costs of components and computing life cycle costs using both Navy and commercial financial parameters. The overall logic flow of COALM during a run is shown in Figure 1-1. The program first processes user input data and then performs engineering and financial calculations. The engineering calculations make use of a file of component cost-versus-capacity curves.

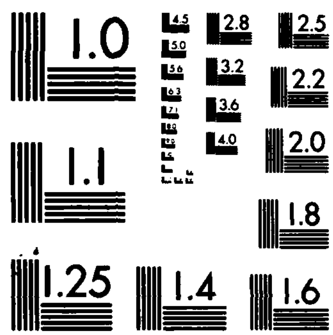
1.1.1 Typical Steam and Power System Designs

COALM offers the flexibility to describe several alternative designs for steam and power systems for Navy bases with dispersed demand points. Three typical designs that have been used to demonstrate the capabilities of COALM are:

- A "steam only" central plant system, such as that shown in Figure 1-2, in which saturated steam is transmitted from the central steam plant to demand points through steam piping.
- A "steam only" decentralized system, such as that shown in Figure 1-3, in which coal is hauled by truck to decentralized boiler plants located at the demand points.

AD-A140 515 A COAL-USE ECONOMICS METHODOLOGY FOR NAVY BASES PHASE II OF ENGINEERING S..(U) BECHTEL GROUP INC SAN FRANCISCO CA A I MCCONE ET AL. FEB 84 NCEL-RR-84.002 2/3

UNCLASSIFIED N62474-82-C-8290 F/G 10/1 NL



MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS-1963-A

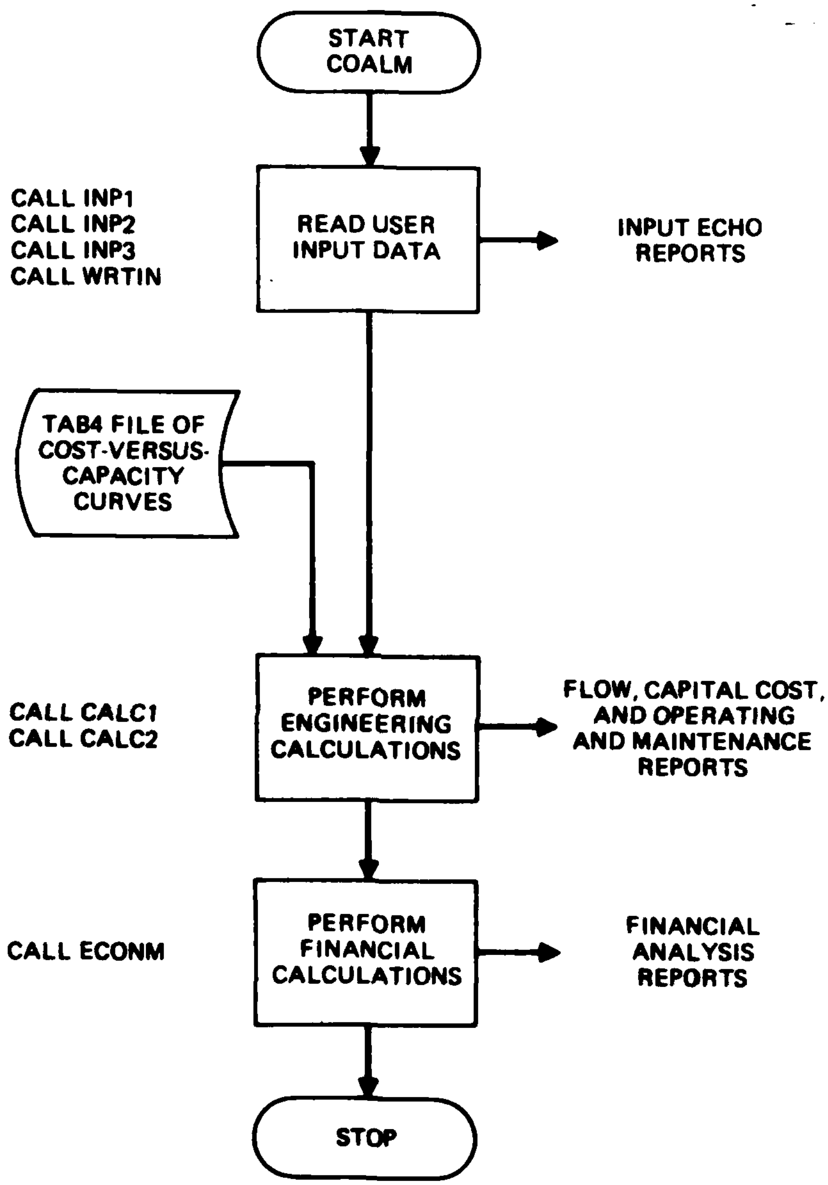


Figure 1-1 OVERALL LOGIC FLOW DIAGRAM FOR A COALM RUN

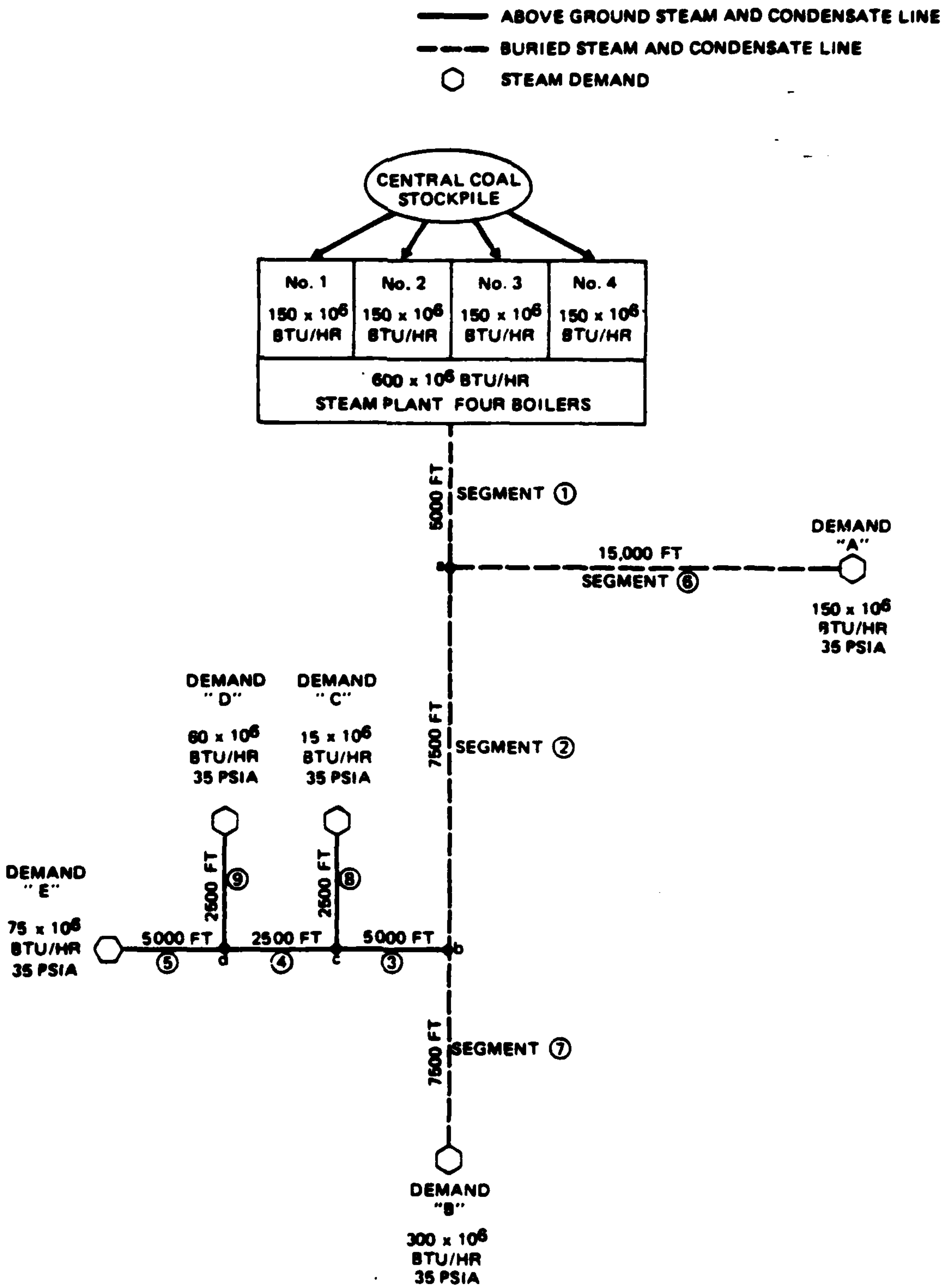


Figure 1-2 EXAMPLE CENTRAL PLANT

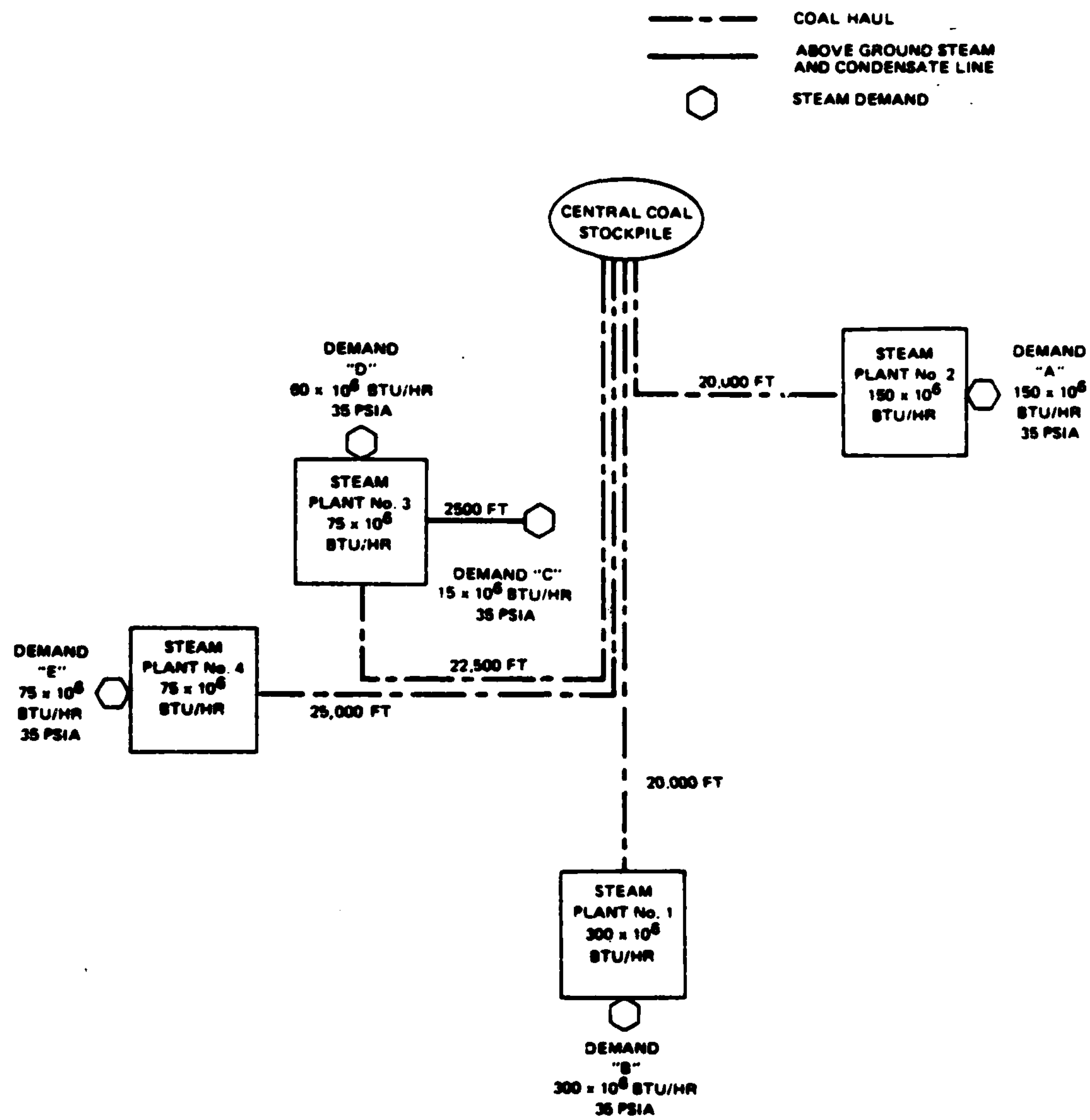


Figure 1-3 EXAMPLE DECENTRALIZED PLANT

- A cogeneration system, in which the central plant boilers generate high pressure steam rather than low pressure steam, and heating steam is extracted from a turbine-generator system.

The three designs, above, are included in a test run that can be reproduced by an interested user.

1.1.2 Module Costs

COALM calculates costs of steam and power system modules using cost versus capacity curves derived from program data tables for total construction costs, annual operating and maintenance labor, and annual operating and maintenance materials. The data base provides modular costs for the following:

- Coal handling facilities
- Coal fired stoker boilers
- Pulverized coal fired boilers
- Baghouse particulates pollution control
- Sulfur dioxide pollution control (scrubbers)
- Coal and waste handling facilities
- Steam distribution piping
- Steam turbines for electricity generation
- Coal mixture fuel preparation facilities
- Retrofit of oil fired and gas fired boilers to burn coal mixture fuels

The program cost data tables include individual boilers ranging in capacity from 25,000 to 250,000 lb/hr of steam, complete plants ranging in capacity from 100,000 to 1,000,000 lb/hr of steam, and turbines ranging in capacity from 2.6 to 25 megawatts. Capacity ranges for other modules have been chosen to match the ranges above for steam and power generation modules.

1.1.3 Flow Calculations

COALM calculates the following flows that impact the cost of steam and power generation:

- Coal consumed
- Auxiliary oil, natural gas, or purchased steam consumed by the steam and power generation system
- Auxiliary electricity consumed
- Scrubber chemicals (lime, limestone, soda)
- Water
- Electricity generated

The flows are calculated by ratio from conceptual designs prepared in previous studies and in the Phase II work. In all cases, the flow calculations are direct, and do not involve any iterative convergence algorithms.

1.1.4 Life Cycle Costs

Life cycle costs are calculated with both Navy and commercial financial parameters, using the coal-use economics methodology developed under Phase I of the contract. Each run of the program generates at least 10 pages of financial reports.

1.1.5 Program Structure

COALM consists of four parts called from the program executive routine:

- Flow and cost calculation routines
- Data table files and interpretation routines
- Financial analysis routines
- Input interpretation routines

The flow and cost calculation routines establish flows of coal, auxiliary energy, and scrubber chemicals and water, based on the plant peak load, annual load factor, combustion efficiency and coal heating value and

sulfur level. Module capacities are then selected from design or average flows, and costs are obtained from curves.

Two files of data tables are used by the program:

- TAB3 - tables in source language, prepared during program development
- TAB4 - tables in machine language, prepared by a special program run during program development

TAB3 tables are in tabular form that can be read and checked by a user. TAB4 tables are in the form of curves produced by the program by least squares fit of log-cost versus log-capacity. The program contains the appropriate special routines to create TAB4 from TAB3. It is expected that the user will not change TAB3 or TAB4. However, Section 5 explains how such changes can be made.

The input interpretation routines accommodate the convenient INFREE free-field input system from the existing NCEL program. This system provides the user the flexibility to input only the information that is actually relevant to his problem.

1.2 PROGRAM FEATURES

COALM offers the user the following coal-use project options:

- Central versus decentralized boiler plants
- Use of coal mixture fuels versus normal coal firing
- Pricing of boilers individually versus pricing in groups of four quarter-sized boilers
- Five possible scrubber types
- Cogeneration versus steam only systems
- Third party financed/Navy operated ventures versus third party financed/third party operated ventures for commercial financial analysis
- Comparison of the cost of the coal-use project with the cost of an alternative project burning either fuel oil or natural gas in existing boilers

1.3 PROGRAM LIMITATIONS

COALM program limitations include the following restrictions on user options and limitations on the program data base:

1.3.1 Restrictions on User Options

- The user must select either a central or a decentralized system. He cannot select a combination of both.

- Only one turbine is included under the cogeneration option. The user cannot define several turbines with capacities of his choice.

- The user must specify the inlet and outlet pressure for each length of steam pipe in his distribution network. The program does not calculate these pressures automatically from steam supply pressure and distribution network geometry.

1.3.2 Data Base Limitations

- Boiler costs in the program are based on typical bituminous coal properties. For unusually poor quality coals, the correct boiler costs might be higher than those calculated by the program.

- Module costs in the program are for a generic typical site. Site specific costs could differ signifcantly from those calculated by the program.

- Costs may not be reliable for modules with sizes significantly outside the range spanned by the cost data tables.

- Most of the cost tables are based on cost estimates prepared in the second quarter of 1978. The program assumes that these costs escalate with general inflation. However, the costs of some modules may in fact be changing at a rate different from general inflation. To assure that the cost tables continue to be correct, they should be reestimated periodically by a qualified architect-engineering contractor.

Section 2

COMPUTATIONAL PROCEDURES

This section presents data and methodology sources for COALM and explains the computational procedures to calculate flows, module costs, total capital and first year operating and maintenance costs, and life cycle costs.

2.1 DATA AND METHODOLOGY SOURCES

The following six NCEL documents are the sources for the data and computational methodology of COALM:

- Reference 2-1 presents the results of the initial study defining flows and parametric costs versus capacity for centralized and decentralized "steam only" plants and centralized cogeneration plants.

- Reference 2-2 extends the Reference 2-1 data base to five different types of sulfur dioxide removal systems (scrubbers).

- Reference 2-3, the Phase II final report under the present contract, presents data on coal mixture fuels, and updates certain data from Reference 2-1.

- Reference 2-4, the Phase I final report under the present contract, outlines the coal-use economics methodology in COALM.

- Reference 2-5, the Phase I computer program user manual, describes the computational procedures used for the economic analyses of COALM.

- Reference 2-6, the Phase III final report under the present contract, provides cost estimates for oil fired and gas fired alternatives displaced by a coal-use project.

2.2 FLOW CALCULATIONS

Flows are calculated by the program for two purposes:

- To establish capacity parameters for module construction, annual labor, and annual material costs

- To permit calculation of costs of purchased energy, chemicals, water, electricity, and waste disposal

COALM calculates the following flows:

- Coal, coal energy, and ash flows
- Boiler and coal handling electricity and water requirements
- Scrubber chemicals, waste, water, and electricity flows
- Coal mixture fuel flows
- Cogeneration steam and electricity flows and adjustments to other flows
- Flows through piping

The calculations for these flows are described briefly below. Variables are defined after their first occurrence.

2.2.1 Coal, Coal Energy, and Ash Flows

The peak coal consumption rate for "steam only" systems is:

$$PCR = PKLOAD \cdot 1{,}000{,}000 / (2000 \cdot EFF \cdot BTU) \qquad (2\text{-}1)$$

where

PCR = peak coal rate, ton/hr

PKLOAD(1) = peak load, 10^3 lb/hr of steam

$$EFF^{(1)} = \left(\frac{\text{Btu heat transferred to steam}}{\text{Btu heating value of fuel}}\right), \text{ dimensionless}$$

BTU(1) = fuel higher heating value, Btu/lb

Equation (2-1) assumes that one pound of steam is generated for each 1000 Btu of heat transferred. PKLOAD, EFF, and BTU are input by the user.

The annual coal requirement is:

$$TNCOL = PCR \cdot FACTLD \cdot 8760. \qquad (2\text{-}2)$$

where

TNCOL = coal requirement, ton/yr

FACTLD(1) = annual load factor, decimal fraction

(1) A user input quantity

The annual fuel energy requirement is:

$$ANEGY = TNCOL \cdot BTU \cdot 2000 / 1,000,000 \qquad (2\text{-}3)$$

Where

ANEGY = fuel energy requirement, 10^6 Btu/yr

The annual heat transferred into steam is the product of ANEGY and EFF, in 10^6 Btu/yr.

The flow of coal ash to waste disposal is proportional to the flow of coal and the percent of ash in the coal (input by the user).

2.2.2 Boiler and Coal Handling Electricity and Water Requirements

Table 2-1 provides factors for computing the electricity requirements of low pressure boilers and coal handling facilities. Table 2-2 provides a factor for computing the water requirements of low pressure boiler systems.

2.2.3 Scrubber Chemicals, Water, and Electricity

COALM provides pollution control systems to meet the emission limit of 1.2 pounds of sulfur dioxide (SO_2) per million Btu of fuel. The pollution control systems (scrubbers) reduce the content of the boiler flue gas to this limit by reacting with and neutralizing any sulfur dioxide in excess of this amount. The following formula gives the tons of sulfur per year, removed from the flue gas by neutralization:

$$TNEUTR = TNCOL \cdot \left(\frac{BTU}{10^6}\right)\left(\frac{PSULF \cdot 10^4}{BTU} - 0.6\right) \qquad (2\text{-}4)$$

where

TNEUTR = sulfur neutralized, ton/yr

PSULF(1) = percent sulfur in coal (input)

This calculation involves the almost exact assumption that 2 pounds of SO_2 are formed for each pound of sulfur burned.

---

(1) A user input quantity

Table 2-1

DATA FACTORS FOR CALCULATING ANNUAL ELECTRICITY REQUIREMENTS FOR BOILERS AND COAL HANDLING FACILITIES

Component	Factor Units	Factor
Low pressure stoker and pulverized coal boiler	Kilowatt hours per 10^6 Btu heat transferred	3.00(1)
Central coal handling facilities	Kilowatt hours per ton of coal handled	3.88(2)

(1) The boiler electricity demand is based on Table A-9 in Reference 2-3.

(2) The coal handling facility electricity demand is based on Tables 8-1 and 8-2 in Reference 2-1.

Table 2-2

DATA FACTOR FOR CALCULATING ANNUAL WATER REQUIREMENTS FOR LOW PRESSURE BOILERS

Component	Factor Units	Factor
Low pressure boiler	10^3 Gallons per 10^6 Btu heat transferred	1.27(1)

(1) This factor is based on Table 4-3 in Reference 2-1.

Table 2-3 then provides factors for computing annual flows of scrubber chemicals, solid and liquid wastes, water, auxiliary steam, and electricity for each of the following five types of scrubbers:

- Limestone
- Lime
- Double alkali
- Soda liquor producing solid waste
- Soda liquor producing liquid waste

2.2.4 Coal Mixture Fuels

For designs that utilize coal mixture fuels, the program calculates the required fuel and ingredient flows that establish costs for on-base mixture fuel preparation facilities.

The weight fraction of coal in the mixture fuel is set by:

$$FRACOL = \begin{cases} 0.5 \text{ for coal-oil mixtures} \\ 0.6 \text{ for coal-water mixtures} \end{cases} \quad (2\text{-}5)$$

The weight fraction of liquid in the mixture fuel is:

$$FRACLQ = 1 - FRACOL \quad (2\text{-}6)$$

The heating value of the mixture fuel is given by:

$$HHVCMF = FRACOL \cdot BTU + FRACLQ \cdot HHVLIQ \quad (2\text{-}7)$$

where

HHVCMF = mixture fuel higher heating value, Btu/lb
HHVLIQ(1) = liquid higher heating value, Btu/lb

The peak demand of mixture fuel energy is:

$$BTUCMF = 10^6 \cdot PKLOAD / EFF \quad (2\text{-}8)$$

where

BTUCMF = peak fuel demand, Btu/hr

(1) A user input quantity

Table 2-3

DATA FACTORS FOR COMPUTATION OF FLOWS
FOR FLUE GAS DESULFURIZATION SYSTEMS (1)

Flow	Factor Units	Lime-stone	Lime	Double Alkali	Soda Liquor Solid Waste	Soda Liquor Liquid Waste
Limestone	Tons per Ton of Sulfur Neutralized	4.32				
Lime for Reaction Plus Lime for Stabilization	Tons per Ton of Sulfur Neutralized	0.270	2.511	2.165		
Soda	Tons per Ton of Sulfur Neutralized			0.199	3.310	3.310
Waste (Cake Plus Stabilization Lime, Excluding Flyash)	Tons per Ton of Sulfur Neutralized	11.12	10.03	9.163	8.743	16.537
Water in Cake	10^3 Gallons per Ton of Sulfur Neutralized	1.45	1.3213	1.178	1.105	2.974
Water for Evaporation to Saturate Gas	10^3 Gallons Per 10^6 Btu of Fuel	0.00669	0.00664	0.00664	0.00669	0.00669
Steam to Reheat Gas	10^3 Pounds per 10^6 Btu of Fuel	0.01937	0.01937	0.01937	0.01937	0.01937
Electricity Proportional to Sulfur	Kilowatt Hours per Ton of Sulfur Neutralized	448	314	162	1030	162
Electricity Proportional to Btu's	Kilowatt Hours per 10^6 Btu'of Fuel	1.53	1.436	0.668	0.646	0.668

(1) The data factors in this table are consistent with Table A-10 of Reference 2-3.

The peak demand tonnages are:

$$WTCMF = BTUCMF / (2000 \cdot HHVCMF) \tag{2-9}$$
$$WTCOAL = FRACOL \cdot WTCMF \tag{2-10}$$
$$WTLIQ = FRACLQ \cdot WTCMF \tag{2-11}$$

where

WTCMF = peak fuel demand, ton/hr
WTCOAL = peak coal demand, ton/hr
WTLIQ = peak liquid demand, ton/hr

The annual tonnages are:

$$TNCMF = ANEGY \cdot 10^6 / (2000 \cdot HHVCMF) \tag{2-12}$$
$$TNCOL = FRACOL \cdot TNCMF \tag{2-13}$$
$$TNLIQ = FRACLQ \cdot TNCMF \tag{2-14}$$

where

TNCMF = mixture fuel, ton/yr
TNCOL = coal, ton/yr
TNLIQ = Liquid, ton/yr

The sulfur content of the mixture fuel is:

$$SCMF = FRACOL \cdot PSULF + FRACLQ \cdot SLIQ \tag{2-15}$$

where

SCMF(1) = Sulfur in mixture fuel, weight fraction
PSULF(1) = Sulfur in coal, weight fraction
SLIQ(1) = Sulfur in liquid, weight fraction

The annual tonnage of sulfur removed by the scrubber is, by analogy with equation (2-4):

$$TNEUTR = TNCMF \cdot \frac{HHVCMF}{10^6} \left(\frac{SCMF \cdot 10^4}{HHVCMF} - 0.6 \right) \tag{2-16}$$

The specific volume of the mixture fuel is:

$$VOLCMF = FRACOL / SGCOAL + FRACLQ / SGLIQ \tag{2-17}$$

where

VOLCMF = specific volume of mixture fuel, dimensionless
SGCOAL(1) = specific gravity of coal, dimensionless
SGLIQ(1) = specific gravity of liquid, dimensionless

(1) A user input quantity

Densities of mixture fuel and mixture liquid are:

$$DENSCM = (1 / VOLCMF) \cdot TPBBL \quad (2\text{-}18)$$
$$DENSLQ = SGLIQ \cdot TPBBL \quad (2\text{-}19)$$

where

DENSCM = density of mixture fuel, tons/barrel
DENSLQ = density of liquid, tons/barrel
TPBBL = conversion factor, tons/barrel

and TPBBL is given by:

$$TPBBL = 62.4 \cdot 231 \cdot 42 / (1728 \cdot 2000) = 0.1752 \quad (2\text{-}20)$$

The annual requirement for the liquid in the mixture fuel is:

$$YGALIQ = TNLIQ \cdot 42 / (DENSLQ \cdot 1000) \quad (2\text{-}21)$$

where

YGALIQ = liquid requirement, 10^3 gallons/year

The average production rate of the mixture fuel preparation facility is:

$$WTMIX = WTCMF \cdot FRACAP \quad (2\text{-}22)$$

where

WTMIX = mixture fuel production rate, tons/hr

$FRACAP^{(1)} = \left(\frac{\text{average production rate}}{\text{peak demand}}\right)$, dimensionless

The mixture fuel storage volume is:

$$BBLSTO = DAYSTO \cdot 24 \cdot WTCMF / DENSCM \quad (2\text{-}23)$$

where

BBLSTO = mixture fuel storage volume, barrels
$DAYSTO^{(1)}$ = days of storage at peak demand

The quantities WTMIX and BBLSTO are used to define the sizes of mixture fuel preparation facilities.

The annual requirement for natural gas to dry coal in a coal oil mixture preparation plant is given by:

$$YCMNG = 311 \cdot TNCOL / 1000 \quad (2\text{-}24)$$

(1) A user input quantity

where

YCMNG = natural gas requirement, 10^3 standard cubic feet per year

The annual requirement for steam to heat the slurry in storage is given by:

$$YCMSTM = 68 \cdot BBLSTO / 1000 \quad (2\text{-}25)$$

where

$$YCMSTM = \text{steam, } 10^3 \text{ lb/yr} \quad (2\text{-}26)$$

The annual electricity consumption of mixture fuel coal grinding and slurry mixing facilities is obtained from the following data tables:

COMEL - electricity for coal-oil mixture facilities
CWMEL - electricity for coal-water mixture facilities

2.2.5 Cogeneration Flows

If cogeneration is selected by the user, the associated flows are calculated using factors from data on pages 9-6, 9-11, 9-12, and 9-13 of Reference 2-1 and in Appendix B of Reference 2-3. The cogeneration plant is optimized for a Navy base with an annual heating steam load factor of 33 percent. The plant contains a high pressure boiler section and a low pressure boiler section, each sized to satisfy 50 percent of the peak heating steam demand. The high pressure system is run continuously. The low pressure system is used during the cold season. The cogeneration plant may have either a condensing or noncondensing turbine generator unit.

The peak heating steam demand in 10^3 lb/hr is:

$$PKHEAT = 10^3 \cdot PKLOAD \quad (2\text{-}27)$$

The annual average steam flows in the cogeneration system are then calculated as dimensionless fractions of PKHEAT. The fractions, called relative flows below, are defined as:

FLWLOP = relative flow, steam from low pressure boiler
FLWHIP = relative flow, extracted, desuperheated steam
FLWCOO = relative flow, cooling steam to condensing turbine
FLWSHV = relative flow, peak shaving steam to condensing turbine
FLWCND = relative flow, steam for base load condensing turbine

The amount of heating steam from the high pressure boiler is, after extraction and desuperheating:

$$FLWHIP = MIN\ (.91 \cdot FACTLD)\ \text{or}\ (0.50) \qquad (2\text{-}28)$$

The amount of heating steam from the low pressure boiler is:

$$FLWLOP = FACTLD - FLWHIP \qquad (2\text{-}29)$$

When the turbine has a condensing section, the other three flows, FLWCOO, FLWSHV, and FLWCND may be nonzero.

When the condensing section is used in the peak shaving mode, then the relative steam flow to peak shaving is:

$$FLWSHV = 0.008 \qquad (2\text{-}30)$$

(which corresponds to fully loading the condensing turbine 3.9 percent of the year). Also, while the condensing turbine is idle, cooling steam must be passed through it, so that:

$$FLWCOO = 0.0217 \qquad (2\text{-}31)$$

If FLWHIP is .5, there will be no steam available for peak shaving. Between FLWHIP = .492 and FLWHIP = .5, peak shaving will be proportionately reduced.

The condensing turbine may be used for base load condensing generation when FLWHIP is less than .492. Then FLWSHV and FLWCOO are zero, and

$$FLWCND = .92 \cdot (.5 - FLWHIP) \qquad (2\text{-}32)$$

However, FLWCND is never allowed to exceed its maximum value of 0.230.

The annual coal energy can now be calculated, by the equation:

$$\text{ANEGY} = \begin{pmatrix} 1.0 & \cdot \text{FLWLOP} \\ + 1.155 & \cdot \text{FLWHIP} \\ + 1.256 & \cdot \text{FLWCND} \\ + 1.256 & \cdot \text{FLWSHV} \\ + 1.256 & \cdot \text{FLWCOO} \end{pmatrix} \cdot \left(\frac{\text{PKHEAT} \cdot 8760}{\text{EFF} \cdot 1000} \right) \qquad (2\text{-}33)$$

The numerical multipliers in equation (2-33) were derived by dividing the cogeneration system enthalpies by the corresponding "steam only" enthalpies.

The annual electricity generation is calculated by the equation:

$$\text{ELPROD} = \begin{pmatrix} \text{FLWHIP} / 18.79 \\ + \text{FLWCND} / \ \ 7.79 \\ + \text{FLWSHV} / \ \ 7.79 \\ + \text{FLWCOO} / 14.50 \end{pmatrix} \cdot (\text{PKLOAD} \cdot 8760) \qquad (2\text{-}34)$$

The annual electricity consumption of the boiler plant is computed as a factor times the already calculated "steam only" electricity consumption. The factors are 1.6 for peak shaving and 2.5 for base load condensing generation.

The annual cooling water consumption of the cogeneration plant is calculated as a factor times the peak heating steam capacity of the plant. The factors, in gallons of water per pound of steam generation capacity, are .0051 for peak shaving and .0393 for base load condensing generation.

When the plant involves cogeneration, all scrubber and mixture fuel flows are multiplied by the ratio of cogeneration annual fuel energy to the "steam only" annual fuel energy.

2.2.6 Piping Flows

The steam flow through each segment of pipe determines the pipe inside diameter through the equation[(2)]:

$$D^{5.21} = .069 \cdot \dot{M}^2 \cdot L / (P_I^{\,2} - P_O^{\,2}) \qquad (2\text{-}35)$$

(2) Reference 2-1, Page 6-4

where

D = diameter, inches
$\dot{M}$ = steam flow rate through the segment, lb/hr
L = pipe segment length, thousands of feet
P_I = inlet pressure, psia
P_O = outlet pressure, psia

The program then selects the correct schedule of pipe from the diameter and inlet pressure(3). Heat losses through the pipe are then calculated for various insulation thicknesses(4) and the most cost effective thickness is selected. Finally, the program calculates and prints the total heat lost in steam transmission. If the user wishes to augment the plant steam demand and load factor to take into account this heat loss, he may do so in a second run of the program.

2.3 MODULE COSTS

COALM reads almost all module costs from data tables in file TAB4. However, the cost of off-base waste disposal is stored in the program as a formula. This section describes the types of tabulated costs, the names and functions of the cost tables, the data sources for the cost tables, the escalation adjustment of the costs to a user-chosen reference date (called a display date), and special adjustments to calculated costs for cogeneration, for mixture fuel utilization, and for separate pricing of individual boilers.

2.3.1 Types of Tabulated Costs

The tables in file TAB4 and its source version, file TAB3, contain costs as a function of capacity for various plant modules. Each table provides one of the following types of information for a module:

- Construction costs
- Annual operating and maintenance material costs
- Annual operating and maintenance labor manhours
- Annual electricity consumption

(3) Reference 2-1, Table 6-1
(4) Reference 2-1, Appendix C

In each table in file TAB3, the dimensional units of the capacity paramenter and the associated costs are cleaıly marked.

2.3.2 Names and Functions of Cost Tables

The cost tables are reproduced in full in Appendix B in a listing of file TAB3. This section indicates the names and functions of the various tables.

Modules in "Steam Only" Plants. The names and functions of cost tables used to compute the costs for modules making up a low pressure steam generation system are shown in Table 2-4. COALM's selection of the data tables depends on the following information input by the user:

- Type of system (centralized or decentralized)
- The sulfur percentage in the fuel

For centralized systems, costs are provided for a cluster of four quarter-sized boilers housed in a single building, with two 60-percent capacity pollution control systems. For decentralized systems, costs are provided for four quarter-sized boilers, each at a different location with a single 100-percent capacity pollution control system and appropriate extra coal handling equipment for storage and feed next to each boiler. Both centralized and decentralized plant systems include a central coal and ash handling facility.

The sulfur percentage in the fuel governs the assignment of a nominal fuel sulfur level and the associated pollution control systems required, as shown in Table 2-5.

The user may select a scrubber system that produces solid waste or one that produces liquid waste. The costs for solid waste scrubbers are higher than for liquid waste scrubbers, and two sets of cost tables are provided, as indicated in Table 2-4.

Table 2-4

NAMES, FUNCTIONS, AND CAPACITY PARAMETERS OF COST DATA TABLES FOR A "STEAM-ONLY" PLANT (1)

Type of Item	Modules Included	Central Plant 1% S	Central Plant 2% S	Central Plant 4% S	Decentralized Boilers 1% S	Decentralized Boilers 2% S	Decentralized Boilers 4% S	Capacity Parameter
Total Construction Costs	Stoker	SGENCPC1 (2)	SGENCPC1	SGENCPC1	SGENCPD1	SGENCPD1	SGENCPD1	Peak Steam Demand (3)
	Baghouses Plus FGD (4)(5) with Solid Waste	POLLCPC1	POLLCPC2	POLLCPC4	POLLCPD1	POLLCPD2	POLLCPD4	Peak Steam Demand
	Baghouses Plus FGD with Liquid Waste		LSODACC2	LSODACC4		LSODACD2	LSODACD4	Peak Steam Demand
	Coal and Ash Handling	COALCONS	COALCONS	COALCONS	COALCONS	COALCONS	COALCONS	Design Coal Rate (6)
	Extra Coal Handling				COALEXDC	COALEXDC	COALEXDC	Design Coal Rate
Annual Labor Hours	Stokers Plus Baghouses	ANNMANC1	ANNMANC1	ANNMANC1	ANNMAND1	ANNMAND1	ANNMAND1	Peak Steam Demand
	FGD with Solid Waste		ANNMANC2	ANNMANC4		ANNAMAD2	ANNMAND2	Peak Steam Demand
	FGD with Liquid Waste		LSODAHC2	LSODAHC4		LSODAHD2	LSODAHD4	Peak Steam Demand
	Coal and Ash Handling	COALMHRS	COALMHRS	COALMHRS	COALMHRS	COALMHRS	COALMHRS	Design Coal Rate
Annual Material Costs	Stoker Plus Baghouses	ANNMTLC1	ANNMTLC1	ANNMTLC1	ANNMTLD1	ANNMTLD1	ANNMTLD1	Peak Steam Demand
	FGD with Solid Waste		ANNMTLC2	ANNMTLC4		ANNMTLD2	ANNMTLD4	Peak Steam Demand
	FGD with Liquid Waste		LSODAMC2	LSODAMC4		LSODAMD2	LSODAMD4	Peak Steam Demand
	Coal and Ash Handling	COALOPS	COALOPS	COALOPS	COALOPS	COALOPS	COALOPS	Design Coal Rate

(1) This tabulation does not include tables for cogeneration or mixture fuel preparation.
(2) The user may select pulverized coal boilers rather than stoker boilers for central plants. The name of the table is PCGNCPCI. Its capacity parameter is the peak steam demand.
(3) The peak steam demand, in 10^3 lb/hr, is the peak demand for heating steam.
(4) FGD denotes fuel gas desulfurization.
(5) FGD is included in Tables POLLCPC2, POLLCPC4, POLLCPD2, and POLLCPD4 (for 2 and 4 percent S). Tables POLLCPC1 and POLLCPD1 contain baghouses only (for 1 percent nominal S level).
(6) The design coal rate, in ton/hr, is 80 percent of the peak coal demand. See page 7-4 of Reference 2-1 for an explanation of the 80 percent factor.

Table 2-5

FUEL SULFUR PARAMETER, NOMINAL SULFUR PERCENTAGE, AND INCLUDED POLLUTION CONTROL SYSTEMS

Fuel Sulfur Parameter Range(1)	Nominal Sulfur Percentage(2)	Included Pollution Control Systems
Less than 0.6	1	Baghouses
0.6 to 3.0	2	Baghouses plus flue gas desulfurization (scrubbers) designed for 2% sulfur fuel
Greater than 3.0	4	Baghouse plus flue gas desulfurization (scrubbers) designed for 4% sulfur fuel

(1) The fuel sulfur parameter is 10^4 · (fuel sulfur percentage) / (fuel heating value, Btu/lb). The fuel sulfur parameter will coincide with the actural fuel sulfur percentage when the fuel heating value is exactly 10,000 Btu/lb. A value of 0.6 for the coal sulfur parameter corresponds to the assumed emission limit of 1.2 lb $SO_2/10^6$ Btu fuel.

(2) The nominal sulfur percentage appears as the right-most digit in table names in Table 2-4.

Coal Mixture Fuel Preparation Modules. Cost data tables for coal grinding and slurry preparation facilities and for mixture fuel slurry storage facilities are named in Table 2-6.

Cogeneration Cost Tables. Cost data tables associated with cogeneration are named in Table 2-7.

Extra Tables for Separate Pricing of Individual Boilers. Cost data tables for baghouse annual labor and materials are named in Table 2-8. These are needed for pricing of central plant systems.

Piping Cost Tables. Piping cost data tables are named in Table 2-9.

2.3.3 Sources of Table Data

Table 2-10 indicates the data sources for the data tables for coal handling, steam and power generation, and pollution control systems.

Table 2-11 indicates the data sources for the data tables for coal mixture fuel preparation facilities. Table 2-12 indicates the data sources for the data tables for piping.

2.3.4 Escalation Adjustment of Costs

COALM uses a cost index procedure to adjust construction and annual materials costs for inflation. The program uses a unit rate procedure to get up-to-date costs for annual labor and electricity.

The construction costs and annual material costs in the tables are valid for the year in which the cost estimates were prepared. The cost index procedure in COALM adjusts the costs for general inflation to some year other than the year of cost estimation. Each construction cost or annual material cost table includes a tabulation of two plant cost indices correct for the year of the cost estimate. The two indices are the following:

Table 2-6

NAMES, FUNCTIONS, AND CAPACITY PARAMETERS OF COST DATA TABLES FOR COAL MIXTURE FUEL PREPARATION FACILITIES

Type of Item	Module	Table Name	Capacity Parameter
Total Construction Cost	COM(1) grinding & mixing	COMCONS	Nominal slurry rate(2)
	CWM(3) grinding & mixing	CWMCONS	Nominal slurry rate
	Slurry storage	STORCONS	Barrels of seasonal storage(4)
Annual Labor Hours	COM grinding & mixing	COMHRS	Norminal slurry rate
	CWM grinding & mixing	CWMHRS	Nominal slurry rate
	Slurry storage	STORHRS	Barrels of seasonal storage
Annual Material Costs	COM grinding & mixing	COMOPS	Nominal slurry rate
	CWM grinding & mixing	CWMOPS	Nominal slurry rate
	Slurry storage	STOROPS	Barrels of seasonal storage
Annual Electricity KWh	COM grinding & mixing	COMEL	Nominal slurry rate
	CWM grinding & mixing	CWMEL	Nominal slurry rate

(1) COM denotes coal-oil mixture.
(2) The nominal slurry rate is the annual average slurry demand, ton/hr, calculated by the program.
(3) CWM denotes coal-water mixture.
(4) The amount of seasonal storage is determined from the number of days of storage at peak load input by the user. A barrel is 42 gallons.

Table 2-7

NAMES, FUNCTIONS, AND CAPACITY PARAMETERS OF COST DATA TABLES FOR COGENERATION FACILITIES

Type of Item	Module	Table Name	Capacity Parameter
Total Construction Costs	Extra costs for HP(1) boilers	COGNCPCB	Peak steam demand (2)
	Extraction condensing turbine	COGNEXTC	Peak megawatts(3)
	Noncondensing turbine	COGNNONC	Peak megawatts

(1) HP denotes high pressure.
(2) The peak steam demand, in lb/hr, is the peak demand for heating steam.
(3) The peak megawatts is the peak electricity production rate of the turbine.

Table 2-8

NAMES, FUNCTIONS, AND CAPACITY PARAMETERS OF COST DATA TABLES FOR BAGHOUSE ANNUAL LABOR AND MATERIALS

Type of Cost	Table Name	Capacity Parameter
Annual Labor Hours	BAGCNTHR	Peak Steam Demand[1]
Annual Material Costs	BAGCNTMT	Peak Steam Demand

(1) Peak steam demand, in 10^3 lb/hr, is the peak demand for heating steam.

Table 2-9

NAMES AND FUNCTIONS OF COST DATA TABLES FOR PIPING[1]

Item Priced	Table Name
Above Surface Schedule 20 Pipe	PIPEAS20
Above Surface Schedule 30 Pipe	PIPEAS30
Above Surface Schedule 40 Pipe	PIPEAS40
Below Surface Schedule 20 Pipe	PIPEBS20
Below Surface Schedule 30 Pipe	PIPEBS30
Below Surface Schedule 40 Pipe	PIPEBS40
Insulation 2 Inches Thick	PIPINS2
Insulation 5 Inches Thick	PIPINS5
Insulation 8 Inches Thick	PIPINS8

(1) The costs provided are construction costs. The capacity parameter in all cases is the pipe diameters, calculated by the program from load demand and pipe run length.

Table 2-10

DATA SOURCES FOR COST DATA TABLES FOR COAL HANDLING, STEAM GENERATION, POLLUTION CONTROL, AND POWER GENERATION SYSTEMS

Type of Item	Table Name	Data Source
Total	SGENCPC1	Table 4-1 of Ref. 2-1
Construction	SGENCPD1	Table 4-1 of Ref. 2-1
Costs	POLLCPC1	Table D-2 of Ref. 2-2
	POLLCPC2	Table D-2 of Ref. 2-2
	POLLCPC4	Table D-2 of Ref. 2-2
	POLLCPD1	Table D-1 of Ref. 2-2
	POLLCPD2	Table D-1 of Ref. 2-2
	POLLCPD4	Table D-1 of Ref. 2-2
	LSODACC2	Table A-2 of Ref. 2-3
	LSODACC4	Table A-2 of Ref. 2-3
	LSODACD2	Table A-1 of Ref. 2-3
	LSODACD4	Table A-1 of Ref. 2-3
	COALCONS	Table 7-3 of Ref. 2-1
	COALEXDC	Table 7-6 of Ref. 2-1
	COGNCPCB	Table 4-2 of Ref. 2-1
	COGNNONC	Table 9-2 of Ref. 2-1
	COGNEXTC	Table 9-2 of Ref. 2-1
	PCGNCPCI	Peter F. Loftus Corporation
Annual	ANNMANC1	Table A-3 and A-4 of Ref. 2-3
Labor	ANNMANC2	Table A-6 of Ref. 2-3
Hours	ANNMANC4	Table A-6 of Ref. 2-3
	ANNMAND1	Table A-3 and A-4 of Ref. 2-3
	ANNMAND2	Table A-5 of Ref. 2-3
	ANNMAND4	Table A-5 of Ref. 2-3
	LSODAHC2	Table A-8 of Ref. 2-3
	LSODAHC4	Table A-8 of Ref. 2-3
	LSODAHD2	Table A-7 of Ref. 2-3
	LSODAHD4	Table A-7 of Ref. 2-3
	COALMHRS	Table 7-5 of Ref. 2-1
	BAGCNTHR	Table A-4 of Ref. 2-3
Annual	ANNMTLC1	Table A-3 and A-4 of Ref. 2-3
Material	ANNMTLC2	Table A-6 of Ref. 2-3
Costs	ANNMTLC4	Table A-6 of Ref. 2-3
	ANNMTLD1	Table A-3 and A-4 of Ref. 2-3
	ANNMTLD2	Table A-5 of Ref. 2-3
	ANNMTLD4	Table A-5 of Ref. 2-3
	LSODAMC2	Table A-8 of Ref. 2-3
	LSODAMC4	Table A-8 of Ref. 2-3
	LSODAMD2	Table A-7 of Ref. 2-3
	LSODAMD4	Table A-7 of Ref. 2-1
	COALOPS	Table 7-5 of Ref. 2-1
	BAGCNTMT	Table A-4 of Ref. 2-3

Table 2-11

DATA SOURCES FOR DATA TABLES FOR
COAL MIXTURE FUEL PREPARATION FACILITIES

Type of Item	Table Name	Data Source
Total	COMCONS	Table 4-3 of Ref. 2-3
Construction	CWMCONS	Table 4-4 of Ref. 2-3
Costs	STORCONS	Table 4-5 of Ref. 2-3
Annual	COMHRS	Table 4-3 of Ref. 2-3
Labor	CWMHRS	Table 4-4 of Ref. 2-3
Hours	STORHRS	Table 4-5 of Ref. 2-3
Annual	COMOPS	Table 4-3 of Ref. 2-3
Material	CWMOPS	Table 4-4 of Ref. 2-3
Costs	STOROPS	Table 4-5 of Ref. 2-3
Annual	COMEL	Table 4-3 of Ref. 2-3
Electricity kWh	CWMEL	Table 4-4 of Ref. 2-3

Table 2-12

DATA SOURCES FOR DATA TABLES FOR PIPING(1)

Table Name	Data Source
PIPEAS 20	Table 6-2 of Ref. 2-1
PIPEAS 30	Table 6-2 of Ref. 2-1
PIPEAS 40	Table 6-2 of Ref. 2-1
PIPEBS 20	Table 6-2 of Ref. 2-1
PIPEBS 30	Table 6-2 of Ref. 2-1
PIPEBS 40	Table 6-2 of Ref. 2-1
PIPINS 2	Table 6-3 of Ref. 2-1
PIPINS 5	Table 6-3 of Ref. 2-1
PIPINS 8	Table 6-3 of Ref. 2-1

(1) All tables are for total construction costs

- The plant cost index published by Chemical Engineering magazine, a McGraw-Hill publication

- A plant cost index published by the Navy

The user is to select one of the two types of cost index for the run he is making. In retrieving a cost from a data table, COALM first divides the cost by the cost index in the table. Then COALM multiplies the resulting quotient by the value of the cost index input by the user.

Annual labor and electricity are expressed in manhours and kilowatt-hours in the data tables. COALM multiplies the quantities retrieved from these tables by $/manhour and $/kilowatt-hour rates input by the user.

2.3.5 Special Adjustments to Module Costs

The program makes adjustments to module costs for the following options desired by a user:

- Cogeneration

- Separate pricing of individual boilers

- Coal mixture fuel utilization

Cogeneration. When a cogeneration option is selected, COALM performs the following steps to arrive at correct module costs:

- The extra construction costs for high pressure boilers are added to the construction costs for a central plant containing four quarter-size low pressure boilers. The total is the cost for a central plant containing two low pressure boilers and two high pressure boilers.

- The contruction cost for a turbine is added to give the cost for steam plus power generation.

- The annual labor for steam and power generation is computed as a factor times the cost for a "steam only" plant. The factor is:

  - 1.44 when the turbine is condensing

  - 1.38 when the turbine is non-condensing

- The annual material for steam and power generation is computed as a factor times the cost for a "steam only" plant. The factor is:
  - 2.0 when the turbine is condensing
  - 1.67 when the turbine is non-condensing
- The construction cost for pollution control is computed as 1.35 times the cost for the "steam only" pollution control system.
- The annual labor for pollution control is computed as 1.68 times the labor for the "steam only" scrubber system and 1.83 times the labor for the "steam only" baghouse system.
- The annual material for pollution control is computed as 1.41 times the material for the "steam only" scrubber system and 1.83 times the labor for the "steam only" baghouse system.

The above factors for steam and power generation were derived from Sections 8 and 9 of Reference 2-1. The factors for pollution control were calculated from the data tables of COALM, assuming that a pair of pollution control systems will be provided for the low pressure boilers and a second, larger pair will be provided for the high pressure boilers.

Separate Pricing of Individual Boilers. When the user selects separate pricing of individual boilers, the program performs the following steps:

- The capacity of the individual boiler is multiplied by 4 to get the capacity of a cluster of 4 boilers.
- The cost tables are called to get costs associated with 4 boilers.
- The costs are then divided by 4.

COALM can perform separate pricing under each of the major plant options available to the user:

- Decentralized "steam only" plant
- Centralized "steam only" plant
- Centralized cogeneration plant

When a decentralized plant is selected, the separate pricing procedure is applied also to the pollution control systems. For central plants, the pollution control systems remain sized to the total capacity of the central plant.

Coal Mixture Fuel Utilization. When the user selects coal mixture fuel utilization, the construction costs for retrofitting coal-capable oil fired or gas fired boilers to coal mixture fuels is calculated as 0.1 times the cost of new stoker boilers of the same capacity. All other costs remain the same.

2.4 TOTAL CAPITAL AND FIRST YEAR OPERATING AND MAINTENANCE COSTS

Once all flows and all module costs are computed, COALM calculates total costs, as follows:

- A total construction cost for the complete plant is formed as the sum of the total construction costs of individual modules.
- Startup costs are computed as 11 percent of all plant construction costs except piping.
- The total capital cost is the sum of the construction costs and the startup costs.
- The total first year operating and maintenance labor manhours is the sum of annual labor manhours for individual modules.
- The total first year operating and maintenance materials cost is the sum of annual material costs for individual modules.
- First year costs for water and scrubber chemicals are formed by multiplying the total annual flows by appropriate input commodity prices. These are added to operating and maintenance materials to get total materials.
- First year costs for purchased energy commodities are calculated from flows and input energy prices. Separate totals are retained for each of the following purchased energy commodities:

- Coal
- Electricity
- Fuel Oil
- Natural Gas
- Steam(5)

2.5 LIFE CYCLE COSTS

Life cycle costs are calculated with both Navy and commercial financial parameters using the coal-use economics methodology in the computer program entitled COALR - Coal Conversion Cost Reformulation Program. The economic analysis routines from COALR have been inserted in toto in COALM. The computation procedures in these routines are described in detail in the COALR user's manual (Ref. 2-5). The economic analyses of both COALM and COALR begin with a cost estimate for plant capital and first year operating and maintenance costs expressed in the dollars of a user-chosen display year. COALM and COALR differ in the way the cost estimate is obtained:

- COALM obtains cost estimate information from the plant cost data base by the calculations described in this section.
- COALR obtains cost estimate information as direct input by the user.

In both programs, the cost estimate information is initially expressed in costs of some base year other than the display year. The programs then convert the cost estimates to display year dollars using the following display year cost parameters input by the user:

- A plant cost index reflecting the general level of costs and prices

(5) Auxiliary steam consumed in scrubbers and coal mixture fuel storage is supplied by the steam plant itself, but an appropriate price for internal cost transfer is charged against the plant.

- An hourly labor rate for operating and maintenance
- Prices for coal, electricity, fuel oil, natural gas, and auxiliary steam

The plant cost index above will be the user's choice of either the cost index published by Chemical Engineering magazine, a McGraw-Hill publication, or a Navy cost index as given in Reference 2-4.

COALM converts the cost estimate information into display year dollars in the following way:

- Construction costs from data tables are divided by a base year cost index that is also in the data tables. The quotient is then multiplied by the display year cost index.
- Costs from the data tables for materials for annual operating and maintenance are adjusted in the same way as construction.
- Labor manhours from data tables for annual operating and maintenance are multiplied by the display year labor rate.
- Purchased energy flows calculated by COALM are multiplied by the corresponding display year purchased energy prices

Section 3

INPUT DESCRIPTION

This section describes the format, preparation, and use of the input data for COALM. Figure 3-1 is the complete set of input data for the example run in Appendix A of this manual. Figure 3-1 is provided for reference during the discussions of this section. Input data for COALM may be prepared either as punched cards or as data files created from a time sharing terminal. In the discussion of this section, lines of input information are referred to as "cards," and the collection of input cards is referred to as the input "deck."

This section contains only information on how to run the current version of the program. Section 5 indicates how to modify program data tables.

3.1 PROBLEM-ORIENTED UNFORMATTED INPUT

COALM employs an easy-to-use input system taken from a previous NCEL computer program developed by Peter F. Loftus Corporation (Reference 3-1), which offers the following convenient features:

- A problem-oriented input language
- Unformatted data

Problem-Oriented Input Language. This includes division of the input deck into 12 logically distinct data sections, and identifies input data by key words that serve both to document input variables for the user and to identify the variable to the program.

Four types of input information are supplied in the problem oriented language:

- Declarations. Each declaration consists of a word or phrase called a "key word." The declaration stands alone, with no numerical values following. Each declaration sets a condition variable in the program.

Table 3-1

EXAMPLE INPUT DATA FOR COALM

```
# 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL
#
PLANT DATA
#
PRESS 300 PEAK LOAD 600 EFF .6 LOAD FACTOR .40
#    PSIA    1000-LB/HR
DECENTRALIZED
#
OIL
SGCOAL 1.4 SGOIL 0.95 SULFUR 1.0 ASH 0.1 BTU 18800
# SPECIFIC GRAVITIES        WT %    WT %    BTU/LB
#
BOILERS 4
LP 1 CAPACITY 300     # 1000-LB/HR
LP 2 CAPACITY 150     # 1000-LB/HR
LP 3 CAPACITY  75     # 1000-LB/HR
LP 4 CAPACITY  75     # 1000-LB/HR
#
COAL DATA             # DISPLAY YEAR PRICE
#
SULFUR 3 ASH 15 BTU 11534 PRICE 30 DIR 5
#   WT %   WT %    BTU/LB    $/TON   %/YR
#
UTILITY DATA          # DISPLAY YEAR PRICES
#
MANHOURS   20         # $/HR
ELECTRIC .025 DIR  6  # $/KWH       , %/YR
GAS      3.20 DIR 10  # $/1000-SCF  , %/YR
STEAM    8.00 DIR  6  # $/1000-LB   , %/YR
OIL       .48 DIR  8  # $/GALLON    , %/YR
WATER     .30         # $/1000-GAL
LIME       50         # $/TON
SODA       70         # $/TON
#
SCRUBBER TYPE
#
DOUBLE ALKALI
#
HAUL DATA
#
OFF 50  # MILES
#
# 1000-LB/HR      MILES
1 LOAD 300 DISTANCE 5
2 LOAD 150 DISTANCE 4
3 LOAD  75 DISTANCE 4.5
4 LOAD  75 DISTANCE 5
#
DISTRIBUTION DATA
#
TAMB 45 # F
#         FT        LB/HR       PSIA      PSIA          F
LENGTH  2500 FLOW  15000 INLET 300 EXIT  30 TSTEAM 358 ABOVE
#
ECONOMIC DATA
#
STARTUP YEAR 1981 MONTH 5
DISPLAY YEAR 1978 MONTH 5
COST INDEX 216.8 CHEM-ENG # DISPLAY YEAR VALUE
SCHEDULE 63,37        # % OF CONSTRUCTION SPENT EACH YEAR
#                       COUNTING BACKWARDS FROM STARTUP
LIFE 25 SALVAGE 0 DISCOUNT 10   # NAVY CONSTANT DOLLAR
# YEARS     $1000        %/YR      DISCOUNT RATE
#
END JOB
```

- Variables. Each variable consists of a word or phrase called a "key word," followed by one or more numerical values.

- Case Titles. A case title is supplied for each distinct case run.

- Comments. Comments aid user documentation and are ignored by the program.

In the discussion that follows, declarations and variables are referred to as "data items."

Unformatted Data. This feature relieves the user of concern about the column in which data is punched and allows the user freedom to provide information on one or several lines, and to include comment information on the same line as data. The input deck is processed by the Peter F. Loftus INFREE free-field input routine, which interprets the information according to the following rules:

- Data may be punched anywhere on a data card.

- Data items may be key words or numbers.

- Data items are separated by a comma, an equal sign, and/or one or more blank spaces.

- Numeric items may be supplied with or without decimal points.

- Numbers in exponential format are supplied by adding a plus or a minus sign followed by the exponent (e.g., 3.4-2 for 3.4×10^{-2}).

- If an alphabetic item contains imbedded spaces, commas, or equal signs, or if it consists only of numbers and plus or minus signs, it should be enclosed by slashes (e.g.,/1A, BC DEF/ or /1234-71/).

- Data items may be repeated on a card by a specification of the form N*D, where N is the number of times data item D is to be repeated.

- Except for the title card, any cards with an asterisk (*) or dollar sign ($) in column 1 are treated as comment cards. Information on such a card is printed in the input echo portion of program output, but is ignored by the program.

- A data card may be terminated by an asterisk or dollar sign preceded and followed by a space. All information to the right of the asterisk or dollar sign on such a card is treated as a comment and will be printed in the input echo but will be ignored by the program.

- Data may be continued on more than one card by punching a blank followed by a plus sign (+) as the last data item on a card not including comments. For example, the following three cards:

```
LENGTH 100 FLOW 200 + $ FIRST CARD
  INLET = 250 +       $ SECOND CARD
  EXIT 30 BURIED      $ THIRD CARD
```

  are equivalent to

```
LENGTH 100 FLOW 200 INLET = 250 EXIT 30 BURIED
```

3.2 INPUT DECK ORGANIZATION

The input data deck for a given run (or "job") may contain a data set for a single case, or it may contain data sets for several cases to be processed in series. The data set for a case is terminated either by the declaration "END CASE" or by "END JOB." After the last data set of the run, supply "END JOB." After each prior data set, supply "END CASE."

The data set for each case is divided into the following twelve sections:

- Title and descriptive information
- Tables
- Plant data
- Coal data
- Utility data
- Scrubber type
- Haul data
- Distribution data
- Cogeneration data

- Economic data
- Comparison data
- Commercial data

The title and descriptive information section must come first, followed by the tables section if it is required. The other sections may be presented in any order. Some sections may be omitted; such sections will be clearly noted in the descriptions below. Within a section, data items may be omitted unless otherwise noted. When a data item is to be omitted, both the key work and any numerical values following it should be omitted. The discussion below will indicate the default values of all variables.

3.3 TITLE AND DESCRIPTIVE INFORMATION

The title and descriptive information section must be the first section of a case data set. The first card must be the title card. It must have an asterisk (*) or dollar sign ($) in Column 1. The remaining columns of the card contain the title that will be printed at the top of output pages.

The user may put additional comment cards in this section to describe the case and the purpose of the run. These cards will appear in the input echo but will be ignored by the program

3.4 TABLES

The tables section permits the user to call for a list of tables from the TAB4 data file. The tables section must follow the title section, if the tables section is required.

The first entry in the tables section must appear by itself on the first card of the section. It is the following declaration:

TABLES

The next data card in the section will contain one of two possible declarations. The first is:

LIST ALL

The card will result in a list of all the tables in TAB4. The alternative declaration is:

LIST ACCESSED TABLES

This card will result in a list of the TAB4 tables utilized for the case.

The table list will appear at the end of the output for the case. If the user merely wants a listing of all the tables in TAB4, the user should add the "END CASE" or "END JOB" card after the TABLES section to terminate the case. Then no further input will be needed on this case.

If, for a particular run, a user wishes to replace a table in TAB3 with a table of the same name containing different data, the instructions in Section 5.2 should be followed.

3.5 PLANT DATA

The first entry for the plant data section is the following declaration appearing by itself on the first card of the section:

PLANT DATA

Input data for the section is placed on subsequent cards.

Plant data contains input data of the following types:

- Basic plant data
- Coal mixture fuel data
- Individual boiler capacity data

3.5.1 Basic Plant Data

The first card contains four variables as data items. The card is as follows, where r denotes a real number:

PRESSURE r1 PEAK LOAD r2 EFF r3 LOAD FACTOR r4

The order of data items on the card is not important. If a data item is omitted, a default value is supplied by the program.

The definitions of the variables on the first card are as follows:

Key Word	Numerical Value	Definition	Units	Default Value
PRESSURE	r1	Pressure of heating steam to distribution piping	psia	0.0
PEAK LOAD	r2	Peak heating steam load of the plant	$\frac{1000\text{-lb}}{\text{hr}}$	0.0
EFF	r3	Combustion efficiency of boilers	decimal fraction	0.8
LOAD FACTOR	r4	Annual plant load factor	decimal fraction	0.0

A second card is supplied to indicate the type of plant, and consists of one of three alternative declarations, as follows:

Alternative Declaration	Interpretation
CENTRALIZED	The plant is a central plant.
DECENTRALIZED	The plant is a decentralized system.
PULVERIZED	The plant utilizes pulverized coal boilers rather than stokers, in a central plant.

If none of the above declarations is supplied, the program will assume CENTRALIZED as a default.

Note that the information on Cards 1 and 2 could be placed on a single card, or could appear on 2 or more cards in any order.

3.5.2 Coal Mixture Fuel Data

If the plant is to burn a coal mixture fuel, at least one additional card must be provided. That card will contain either of the following alternative declarations:

Alternative Declaration	Interpretation
OIL	The fuel is a coal-oil mixture.
WATER	The fuel is a coal-water mixture.

The following additional data items may be supplied, where r signifies a real number:

```
SGCOAL r1 SGLIQUID r2
SULFUR r3 ASH r4 BTU r5
```

These variables are defined as follows:

Key Word	Numerical Value	Definition	Units	Default Value Coal-Oil	Default Value Coal-Water
SGCOAL	r1	Specific gravity of coal	dimensionless	1.4	1.4
SGLIQUID	r2	Specific gravity of liquid	dimensionless	0.95	1.0
SULFUR	r3	Sulfur content of liquid	wt. %	0.9	0.0
ASH	r4	Ash content of liquid	wt. %	0.0	0.0
BTU	r5	Higher heating value of liquid	Btu/lb	18,800.	0.0

3.5.3 Individual Boiler Capacity Data

The program normally prices the boiler plant assuming that it contains four quarter-sized boilers with a total capacity equal to PEAK LOAD. The user may wish instead to call for separate pricing of up to 20 individual boilers with various capacities. To assure cost consistency, the user should arrange that the capacities of the individual boilers add up to PEAK LOAD.

To call for separate pricing of individual boilers, the user supplies the following card:

```
BOILERS n
```

Here, n is the number of individual boilers, a positive integer.

The user must next supply n cards with individual boiler data. Each card must be of either of the following forms:

```
LP i CAPACITY r
```

or

```
HP i CAPACITY r
```

Here, LP indicates a low pressure boiler, and HP indicates a high pressure boiler (needed for cogeneration). The integer i is the boiler number (ranging from 1 to n in the order of appearance of the cards). The capacity, r, is in thousands of pounds of steam per hour.

3.6 COAL DATA

This section describes the coal to be used. The first card of the section must contain the declaration

```
COAL DATA
```

On a subsequent card or cards in the section, the user supplies the following, where r signifies a real number:

SULFUR r1 ASH r2 BTU r3 PRICE r4 DIR r5

These variables are defined as follows:

Key Word	Numerical Value	Definition	Units	Default Value
SULFUR	r1	Sulfur content of coal	Wt. %	0.0
ASH	r2	Ash content of coal	Wt. %	0.0
BTU	r3	Higher heating value of coal	Btu/lb	0.0
PRICE	r4	Delivered price of coal	$/ton	0.0
DIR	r5	Differential inflation rate of coal	%/yr	0.0

3.7 UTILITY DATA

This section provides rate information for labor, purchased energy, water, and scrubber chemicals. The first card of the section must contain the following declaration:

UTILITY DATA

Subsequent cards that may be supplied are as follows, where r signifies a real number:

MANHOURS r1
ELECTRIC r2 DIR r10
GAS r3 DIR r11
OIL r4 DIR r12
STEAM r5 DIR r13
WATER r6
LIME r7
LIMESTONE r8
SODA r9

The rate variables in the cards above are defined as follows:

Key Word	Numerical Value	Definition	Units	Default Value
MANHOURS	r1	Labor rate	$/manhour	0.0
ELECTRIC	r2	Electricity rate	$/kWh	0.0
GAS	r3	Natural gas rate	$ per thousand standard cubic feet	0.0
OIL	r4	Fuel oil rate	$/gallon	0.0
STEAM	r5	Auxiliary steam rate	$/1000-lb	0.0
WATER	r6	Water rate	$/1000-gal	0.0
LIME	r7	Lime rate	$/ton	0.0
LIMESTONE	r8	Limestone rate	$/ton	0.0
SODA	r9	Soda rate	$/ton	0.0

All rates must be in display year dollars.

The key work DIR on the cards above denotes the differential inflation rate for the purchased energy commodity preceding it on the line. The numerical values r10, r11, r12, and r13 are expressed in percent per year.

The default value for each DIR is zero.

3.8 SCRUBBER DATA

This section selects the type of flue gas desulfurization system (scrubber). The section must be included if the fuel sulfur level will require flue gas desulfurization. The first card of the section contains the declaration:

SCRUBBER DATA

The next card of this section contains one of five alternative declarations, which are defined as follows:

Alternative Declaration	Interpretation
LIMESTONE	Limestone scrubbers are selected.
LIME	Lime scrubbers are selected.
DOUBLE ALKALI	Double alkali scrubbers are selected.
SOLID SODA	Soda liquor scrubbers with liquid waste are selected.
LIQUID SODA	Soda liquor scrubbers with liquid waste are selected.

3.9 HAUL DATA

This section describes hauling distances. The first card of the section contains the declaration:

HAUL DATA

The next card of the section is as follows, where r signifies a real number:

HCOAL r1 ASH r2 SLUDGE r3 OFF r4

The definitions of these variables are:

Key Word	Numerical Value	Definition	Units	Default Value
HCOAL	r1	Distance for transporting coal from coal pile to central plant	Miles	0.0
ASH	r2	Distance for transporting ash from central plant to on-base waste collection terminal	Miles	0.0
SLUDGE	r3	Distance for transporting sludge from central plant to on-base waste collection terminal	Miles	The value for ash
OFF	r4	Distance for transporting ash and sludge from on-base terminal to off-base permanent disposal site	Miles	0.0

The data items on the above card may be presented in any order, and any or all may be omitted.

If the plant is decentralized, a card of the following form must be supplied for each decentralized boiler station:

i LOAD r1 Distance r2

Here, i is the boiler station identification number (an integer between 1 and 10) and r designates a real variable. The other variables on the card are:

Key Word	Numerical Value	Definition	Units
LOAD	r1	Steam production capacity of boiler station i	$\frac{1000\text{-lb}}{\text{hr}}$
DISTANCE	r2	Distance from station i to the central coal pile/waste terminal	Miles

3.10 DISTRIBUTION DATA

This section describes steam distribution piping. The section is optional. The first card of the section must contain the declaration:

DISTRIBUTION DATA

The next card is:

TAMB r1

Here, r1 is the ambient temperature in fahrenheit. The default value is 0.0.

Next, a separate card must be supplied describing each segment of pipe. Up to 50 segments may be described. Each card has the following form, where r designates a real number:

LENGTH r1 FLOW r2 INLET r3 EXIT r4 TSTEAM r5 a

The last entry on the card, denoted by a, is one of the following two alternative declarations:

Alternative Declaration	Interpretation
ABOVE	The pipe segment is above ground.
BURIED	The pipe segment is buried.

If the declaration is omitted, above ground is assumed.

The five variables on the card are defined as follows:

Key Word	Numerical Value	Definition	Units	Default Value
LENGTH	r1	Length of pipe segment	feet	0.0
FLOW	r2	Steam flow rate through segment	$\frac{1000\text{-lb}}{\text{hr}}$	0.0
INLET	r3	Inlet steam pressure	psia	0.0
EXIT	r4	Exit steam pressure	psia	0.0
TSTEAM	r5	Inlet steam temperature	F	0.0

3.11 COGENERATION DATA

The section is optional. The first card of the section contains the following declaration:

COGENERATION DATA

The next card must contain one of the following three alternative declarations:

Alternative Declaration	Interpretation
NONCONDENSING	Power is cogenerated in a non-condensing turbine.
CONDENSING PEAK SHAVING	Power is cogenerated in a condensing extraction turbine, with condensing generation for peak shaving.
CONDENSING	Power is cogenerated in a condensing extraction turbine, with maximum condensing generation.

3.12 ECONOMIC DATA

This section describes economic parameters. The first card of this section contains the following declaration:

ECONOMIC DATA

Three cards must now be supplied. The data items on each card must be supplied in the order shown. The three cards are:

STARTUP YEAR i1 MONTH i2
DISPLAY YEAR i3 MONTH i4
COST INDEX r1 a

In the above, i designates an integer, r designates a real number, and a indicates a declaration.

The integers on the first and second cards above are input as follows:

i1 - the startup year, in four digits
i2 - the startup month, an integer between 1 and 12
(if omitted, 1 is assumed)
i3 - the display year, in four digits
i4 - the display month, an integer between 1 and 12
(if omitted, 1 is assumed)

The symbol "a" on the cost index card above indicates one of the following two alternative declarations:

Alternative Declaration on the Cost Index Card	Interpretation
NAVY	The input cost index is the Navy cost index.
CHEM-ENG	The input cost index is the cost index published by Chemical Engineering magazine.

The number r1 on the cost index card is the display year value of the cost index selected by the declaration above.

A schedule card must be supplied. This card has the form:

SCHEDULE r1 r2 r3 r4 r5

The numbers r1, r2, etc. are percentages of the construction costs in years preceding startup of plant operation, counting backwards from startup. The percentages must add up to 100 percent. For construction periods shorter than five years, only those percentages that are nonzero must be entered.

Three additional data items may be supplied on one or more card in any order. Shown on a single card, these are as follows:

LIFE r1   SALVAGE r2   DISCOUNT r3

Here, r designates a real number. The variables are defined as follows:

Key Word	Numerical Value	Definition	Units	Default Value
LIFE	r1	Economic life of the plant	Years	25.0
SALVAGE	r2	Salvage value of plant at end of economic life	Thousands of dollars	0.0
DISCOUNT	r3	Navy constant dollar discount rate	Percent/year	10.0

3.13 COMPARISON DATA

This section determines the type of base case against which the coal-use plant is compared. The first card of this section contains the declaration:

COMPARISON DATA

The next card contains one of the following two alternative declarations:

Alternative Declaration	Interpretation
BURN OIL	A base case burning fuel oil in existing boilers is selected.
BURN GAS	A base case burning natural gas in existing boilers is selected.

3.14 COMMERCIAL DATA

This section describes private sector financial assumptions. The first card of this section contains the following declaration:

COMMERCIAL DATA

The second card of the section is:

INFLATION r1

Here, r1 is the general inflation rate in percent/year.

The third card of the section defines the private sector capital structure, as follows, where r signifies a real number:

DEBT r1 INTEREST r2 RETURN r3

The variables are defined as follows:

Key Word	Numerical Value	Definition	Units	Default Value
DEBT	r1	The amount of the project capital that is financed by debt	Percent	0.0
INTEREST	r2	The current dollar rate of interest on debt	Percent per year	0.0
RETURN	r3	The current dollar rate of return on equity	Percent per year	0.0

The fourth card of the section contains one of the following two alternative declarations:

Alternative Declaration	Interpretation
PRIVATE	A venture structure is selected that is third party financed and third party operated (all private).
THIRD PARTY	A venture structure is selected that is third party financed and Navy operated.

If the THIRD PARTY alternative is selected, the following additional variable may be supplied on the same or following card:

LEASE LIFE r1

Here, r1 is the duration of the lease agreement between the third party and the Navy, expressed in years. The default value is 15 years.

The next two cards define tax information. They are of the following form, where r is a real number:

INCOME TAX RATE r1 CREDIT r2
PROPERTY TAX PERCENT r3

These variables are defined as follows:

Key Word	Numerical Value	Interpretation	Units	Default Value
INCOME TAX RATE	r1	Federal plus state corporate income tax rate	Percent of annual taxable income	50.0
CREDIT	r2	Investment tax credit	Percent of investment	10.0
PROPERTY TAX PERCENT	r3	Annual property tax rate	Percent of total capital requirement per year	0.0

The last card defines the calculation of depreciation for tax purposes. The card has the form:

DEPRECIATION a LIFE r1

In the above, "a" is one of the following two alternative declarations about the method for computing year-by-year depreciation:

Alternative Declaration	Interpretation
DEPRECIATION SOYD	The sum of the year's digits method is selected.
DEPRECIATION ACRS	The accelerated capital recovery method is selected. (The default is the ACRS method.)

On the last card above, the number r1 is the plant life for tax depreciation purposes, expressed in years. The default value is 5 years.

Section 4

PROGRAM OUTPUT

This section describes the output of COALM. The basis for the discussion in this section will be the example of the output of a typical run, selected to demonstrate most of the features of the program. This output is provided in Appendix A, in three parts, as Tables A-1, A-2, and A-3. The example run describes a "steam only" Navy base heating system with the following characteristics:

- A decentralized configuration corresponding to Figure 1-2 capable of generating 600,000 lb/hr of steam
- Separate pricing of individual boilers
- Coal-capable, oil-fired boilers retrofitted to consume a coal-oil mixture
- A central coal pile/waste terminal and nearby coal-oil mixture preparation and storage facilities
- Hauling of fuel and waste between a central fuel/waste terminal and the decentralized boiler stations
- Steam distribution piping
- Flue gas desulfurization

The output of the example run contains the following parts:

- An echo of input data
- Flows, and capital and first year costs of the plant
- Financial analysis reports

Each of these parts is described briefly below.

4.1 INPUT DATA ECHO

The first part of the output is the input data echo, Table A-1. The input data echo is divided into two segments:

- Blind echo
- Interpretive echo

The blind echo is merely an immediate reprinting in the output of the data fed in as input. The blind echo of the example run is shown on the first two pages of Table A-1 under the heading "Input Data Listing." The input data in the example was prepared in the sequence indicated in Section 3. The example input makes extensive use of comments in order to clearly label the units and interpret input variables and declarations. This procedure may be useful for other users.

The interpretive echo proves to the user that his input data has been correctly stored in program internal variables. In Table A-1, the interpretive echo is displayed in four pages.

4.2 FLOWS, CAPITAL COSTS, AND FIRST YEAR COSTS

The next part of the output presents flows, capital costs, and first year costs calculated by the program. Table A-2 shows this part of the output for the example run. The output contains calculation results and a summary.

The calculation results headings are:

- Individually priced boilers
- Boiler plant performance
- Boiler and pollution control total construction cost
- Boiler and baghouse annual requirements
- Scrubber labor, utility, and waste requirements
- Coal and waste handling
- Coal handling facility

- Decentralized handling and hauling
- Steam transmission system costs

The summary includes headings for the following capital costs:

- Construction costs
- Startup costs

The first year costs included in the summary consist of operating and maintenance costs (capital charges are not included here but are computed in the financial analysis section). The summary includes headings and tabulations for the following first year costs:

- Total operating and maintenance labor costs
- Total electricity costs
- Total operating and maintenance material costs
- Oil costs
- Coal costs

4.3 FINANCIAL ANALYSIS REPORTS

The final part of the output presents the financial analyses reports generated by the coal-use economics methodology (References 2-4 and 2-5). Table A-3 presents the financial analysis reports generated for the example run. The reports describe two ventures which can be compared side-by-side:

- A Navy financed/Navy operated venture
- A third party financed/Navy operated venture

The titles of the reports in Table A-3 are as follows:

- Navy present values in display year dollars
- Navy levelized costs in display year dollars
- Navy life cycle cost and benefits analysis

- Navy present values in startup year dollars
- Navy levelized costs in startup year dollars
- Third party financing investor cash flows during contruction period
- Third party financing investor cash flows during operating period
- Third party financing Navy cash flows during operating period
- Summary economic statistics

If the input had called for a commercial venture, that is third party financed and third party operated (all private), the following reports would have been produced instead of third party financing reports:

- Private venture minimum revenue requirement discounting with weighted cost of capital
- Private venture minimum revenue requirement discounting with return on equity
- Private venture investor cash flows during construction period
- Private venture cash flows during operating period

If the input had described a plant with cogeneration, the program would have produced two extra Navy financial analysis reports, one in display year dollars and one in startup year dollars, that describe the incremental costs or savings resulting from inclusion of electricity cogeneration in the plant.

Section 5

TABLES

This section describes the data tables that can be printed with the output of a case run. It also indicates how the program can be used to change or replace File TAB4 that is used in a case run.

5.1 LISTING OF DATA TABLES

If the user has included a tables section in his case input, his output will include listings of data tables.

Each data table listed will appear as a separate page in the output listing of data tables. Table 5-1 is the output page for a typical data table. The following remarks should facilitate interpretation of table output.

- The top line. This contains:
  - TABLE a, where "a" is the table name
  - Type i, where "i" is an integer available to the user for additional notation
  - XX = a, where "a" signifies the functional form of the independent capacity variable x in the least squares fit of the cost vs capacity data. "a" can take on either the value "x" or the value "LOG x", where "LOG" signifies the logarithm to the base 10.
  - yy = a, where a signifies the functional form of the dependent cost variable y. a can take on either the value "y" or the value "LOG y."
  - i ENTRIES, where i signifies the number of cost versus capacity entries in the table
- The second line. This line is the title of the table.

Table 5-1

OUTPUT PRODUCED BY TABLE LIST
COMMAND FOR A TYPICAL DATA TABLE

TABLE SGENCPC1   TYPE 1   XX=LOG X VS YY=LOG Y   5 ENTRIES

CONSTRUCTION COSTS, STOKERS, CENTRAL PLANT

COST INDEX 1   YY = 2.77127 + -.21382 XX + -.00631 XX**2

COST INDEX 2   YY = 1.92835 + -.21382 XX + -.00631 XX**2

ENTRY	X	Y	INDEX 1	INDEX 2	CALCULATED POINTS 1	CALCULATED POINTS 2
1	100.0	45000.0	216.8	1510.0	45128.7	45128.7
2	200.0	38500.0	216.8	1510.0	38187.3	38187.3
3	400.0	32000.0	216.8	1510.0	32228.6	32228.6
4	800.0	27125.0	216.8	1510.0	27128.2	27128.2
5	1000.0	25700.0	216.8	1510.0	25650.2	25650.2

- The third line. This line shows the least squares fit equation when the cost entries are divided by cost index number 1 (Chemical Engineering).

- The fourth line. This line shows the least squares fit equation when the cost entries are divided by cost index number 2 (Navy).

- The fifth and sixth lines. These provide headings for the table of data entries.

- Entry lines. One line of data is provided for each cost versus capacity data point, columns 2 through 5 echo the input data for the entry. Columns 6 and 7 show how the fit equations approximate the value of y for the entry value of x.

If the reader is interested in the units of the capacity and cost variables x and y, he should read these in the listing of TAB3 provided in Appendix B of this manual.

5.2 CHANGING OR REPLACING DATA TABLES

The program COALM has special routines to create or change the data table file TAB4. The current version of TAB4 was created from TAB3, a file of data tables in input language that can be read by the user. Changes to TAB4 can be made by one of the following two procedures:

- Submit individual new or replacement tables as input and produce a modified TAB4.

- Change or add to data table master file TAB3 and submit the modified TAB3 as input to create TAB4 over again.

If a single listing of all current data tables in user-readable form is desired, the second procedure should be followed.

5.2.1 Individual New or Replacement Data Tables

Individual new or replacement data tables are entered as part of the tables section of input. This section immediately follows the title of the run. The first card of the tables section is:

TABLES

The next card is:

INCLUDE

Following this, insert the input for one or more data tables. Each data table will consist of the following parts:

- A name card
- A title card
- Data cards

The name card must be of the following form:

al TYPE il CURVE i2 N i3 a2

In the above, i denotes an integer, and a indicates a declaration. The entries on this card are defined as follows:

- al is the name of the data table. It consists of 1 to 8 alphabetic characters, one of which must be alphabetic.
- il is a 1- or 2-digit integer available to the user for additional notation.
- i2 indicates the functional forms of the cap^^ity variable x and cost variable y in the quadratic curve fit equation. The allowed values of i2 and the functional forms of x and y in the fit equation are:

Value of i2	Functional Forms in Fit Equation	
1	x	y
2	$Log_{10}x$	y
3	x	$Log_{10}y$
4	$Log_{10}x$	$Log_{10}y$

- i3 is the number of data sets that are provided on data cards.

- a2 is the declaration:

  REPLACE

  This declaration is used if the data table replaces a table of the same name already existing in TAB4. For instance, if the data table is to replace the first table of TAB3 in Appendix B, the first card of the user's replacement table will read:

  ANNMTLC1 TYPE 1 CURVE 4 N 5 REPLACE

  The declaration a2 is omitted if the table is an additional table.

The title card has the form:

TITLE/string/

Here, "string" denotes a title for the table.

The typical data card is of the form:

r1 r2 r3 r4

Here, r denotes a real number. The entries on the data card are defined as follows:

- r1 - the capacity variable x
- r2 - the cost variable y
- r3 - the *Chemical Engineering* magazine cost index for the date of the estimate of cost variable y
- r4 - The Navy cost index for the date of the estimate of cost variable y

If the variable y is in manhours or kilowatt-hours rather than in dollars, the number 1.0 should be input for r3 and r4.

Up to 50 data cards of this form may be accommodated in a table. The user may find it convenient to define the units of variables x and y in a comment card placed ahead of the data cards.

5.2.2 Revision of Data Table Master File TAB3

The master file TAB3 can be revised by replacement and addition of tables, and then submitted as new input to create TAB4 over again. The format for the replacement or additional tables is as described above.

The current version of master file TAB3 is reproduced in Appendix B. Instructions for executing a run with TAB3 as input are provided in Section 6.

Section 6

PROGRAM EXECUTION

This section presents instructions for executing COALM on the computer designated KWA at Control Data Corporation's Western Cybernet Center in Sunnyvale, California. Instructions are provided for execution in either of the following modes:

- Batch
- Demand (through the SUBMIT command)

Instructions are provided for the following seven operations:

- Run COALM with user input cases
- Run COALM with EXAMPLM example input case
- Run COALM with XMPLMF test input case
- Run COALM with TABFLO test input cases
- Generate a compilation listing of COALM
- Run COALM to generate a listing of TAB3
- Run COALM with user data tables and cases

The instructions for the operations above utilize the procedure file COALPRC, which is a permanent public file under user number L6016GS. Procedures in File COALPRC automatically retrieve program files, data tables, and sample and test input data from a program tape and provide routine control statements to complete a run.

6.1 BATCH MODE EXECUTION

Batch mode execution is accomplished by submission of a deck of run cards. This run deck consists of the following set of cards in the order shown:

- Identification cards
- Procedure cards
- An end-of-record card
- Input data cards
- An end-of-information card

Each of these are discussed below.

6.1.1 Identification Cards

Table 6-1 displays typical identification cards for use of COALM. The table provides a brief explanation of the contents of each card. This explanation is provided for information only. Since several of the cards are user-specific and installation-specific, the user must consult local Control Data Corporation representatives for assistance in preparing correct identification cards.

6.1.2 Procedure Cards

These cards will perform the required operations to run COALM. They are the same in batch and demand mode. They are discussed in Section 6.3.

6.1.3 End-of-Record Card

After the last procedure card, an end-of-record card must be placed. It consists of the numerals 7, 8, and 9 punched in column 1. It is used if input data cards follow.

6.1.4 Input Data Cards

User input data cards are placed after the end-of-record card. If the procedure needs no user input data, or if the required data is to be obtained from a disc file, no input cards are to be provided, and the preceding end-of-record card is deleted.

Table 6-1

TYPICAL BATCH MODE IDENTIFICATION CARDS

Card Number	Card Contents	Explanation
1	JOB,P4,T100,STKWA.	JOB indicates the start of information for a job. P4 indicates assignment of job priority 4. T100 indicates a limit of 100 seconds for the job. STKWA indicates that the job will utilize the Sunnyvale computer designated KWA. The terminal period indicates the end of the job control card. Each control card in a batch deck must end with a period.
2	USER,XX999YY,PASSWORD,KWA.	USER indicates that user identification data follows. XX999YY is a typical form of user number. PASSWORD is the user's password. KWA indicates that the user number is assigned to computer KWA.
3	CHARGE,WW9992Z,*QQ9*PN999.	CHARGE indicates that user accounting data follows. WW9992Z is a typical form of charge number. *QQ9*PN999 is a possible form of program and individual user number.
4	ROUTE,OUTPUT,DEF,DC=PR,ST=WCZ,UN=MKIVPW,FID=MYNAME.	ROUTE indicates that the output should be printed at a location other than the Sunnyvale computer center. OUTPUT is the name of the file to be routed. DEF indicates that routing is deferred until the run is complete. DC=PR indicates that the output device is a printer. ST=WCZ indicates the Sunnyvale output queue holding the output. UN=MKIVPW indicates that that the printer is in the San Francisco data center. FID=MYNAME indicates that MYNAME is to be printed on the output.
5	HEADING.M1MYNAME (This card is optional.)	HEADING indicates that a heading is to be printed on the first run page. The period after HEADING ends the heading command. M is the character used to print the heading. 1 indicates that the heading will be printed at the top of the next page. MYNAME is the heading to be printed, up to 10 characters; the user's name is the heading recommended.
6	GET,FILENAM. (This card is optional, and is used if input data is on disc rather than on cards.)	GET indicates that a data file is to be made a local file for the user's run. FILENAM is the name of the data file.

6.1.5 End-of-Information Card

After the last input data card (or last procedure card if there are no input data cards), an end-of-information card must be placed. It consists of the numerals 6, 7, 8, and 9 punched in column 1.

6.2 DEMAND MODE EXECUTION

Demand mode execution from a timesharing terminal is accomplished by the following steps:

- o Creation of a disc file containing the job control statements
- o Submission of the file as a remote batch job

6.2.1 Creation of Job Control File

From a timesharing terminal, the user can create a job control file using the text editor[(1)]. The file may be of either of the following two forms:

- o The statements and data lines are identical to the cards of the equivalent batch job deck.
- o Most statements are identical to cards in the equivalent batch job deck. An interpretive feature permits substituting commands that may be shorter for some statements.

Table 6-2 describes a typical demand mode job control file that includes the interpretive feature. When working from the terminal, it is usually most convenient to prepare input data as a separate file rather than to include it in the job control file. In that case, the data file is brought into the job by the GET command shown in Tables 6-1 and 6-2.

---

(1) For instructions on the use of the XEDIT text editing system, the user should consult Control Data Corporation documentation.

Table 6-2

TYPICAL DEMAND MODE JOB CONTROL FILE

Line Number	Line Contents		Explanation
1	/JOB		This announces the use of the interpretive feature.
2	JOB,P4,T100.		This line is substituted for the batch mode JOB card.
3	/USER		This line commands the computer to retrieve user number, password, and computer assignment from the terminal session submitting the job.
4	/CHARGE		This line commands the computer to retrieve accounting data from the terminal session submitting the job.
5	ROUTE,OUTPUT,DEF,DC=PR,ST=WC2,UN=MKIVPW,FID=MYNAME.		These lines are identical to the corresponding batch mode cards.
6	HEADING.M1MYNAME	(Optional)	
7	GET,FILENAM.	(Optional)	
8,...,n	(Procedure lines)		These lines are identical to the corresponding batch mode cards.
n + 1	/EOR	(Optional)	This line substitutes for the end-of-record batch mode card.
n + 2,...,m	(Data lines)	(Optional)	These lines are identical to the corresponding batch mode cards.
m + 1	/EOF		This line substitutes for the end-of-information batch mode card.

6.2.2 Submission of Job Control File

Submission of the job from the terminal is accomplished by the lines shown in the following example:

```
GET,JCFILE
SUBMIT,JCFILE
```

In the first line, the GET command brings the disc file named JCFILE into the user's computer workspace. JCFILE is the file of job control statements. In the second line, the SUBMIT command submits file JCFILE as the job control statements for a remote batch job.

6.3 PROCEDURE STATEMENTS

Procedure file COALPRC contains a series of procedures to carry out operations with COALM. Brief procedure statements will then permit the user to execute the procedures. The following paragraphs explain the procedure statements for seven operations with COALM.

6.3.1 Run with User Input Cases

To run COALM with input cases prepared by the user, include the following procedure statements as cards or file lines:

```
GET,COALPRC/UN=L6016GS.
BEGIN,MUSRDAT,COALPRC,I=FILENAM.
```

In the first card, the command GET makes the procedure file COALPRC a local file for the user's run. In the second card, the command BEGIN executes a procedure named MUSRDAT which is found in file COALPRC. FILENAM is the name of the user's file containing input cases. This file may be on disc, or it may be the file created when input data cards or lines are read into the computer with the job control deck.

6.3.2 Run with EXAMPLM Sample Input Case

The sample output of Appendix A is generated by a run with an input data file labeled EXAMPLM. To replicate that run, include the following procedure statements as cards or file lines:

```
GET,COALPRC/UN=L6016GS.
BEGIN,MXPLDAT,COALPRC.
```

In the first card, the command GET makes the procedure file COALPRC a local file for the user's run. In the second card, the command BEGIN executes a procedure named MXPLDAT which is found in file COALPRC.

6.3.3 Run With XMPLMF Test Input Cases

A series of test cases can be run using a file named XMPLMF. To make a run with this file of input cases, include the following procedure statements as cards or file lines:

```
GET,COALPRC/UN=L6016GS.
BEGIN,MXMFDAT,COALPRC.
```

In the first card, the command GET makes the procedure file COALPRC a local file for the user's run. In the second card, the command BEGIN executes a procedure named MXMFDAT which is found in file COALPRC.

6.3.4 Run with TABFLO Test Input Cases

A series of test cases can be run using a file named TABFLO. To make a run with this file of input cases, include the following procedure statements as cards or file lines:

```
GET,COALPRC/UN=L6016GS.
BEGIN,MTFLDAT,COALPRC.
```

In the first card, the command GET makes the procedure file COALPRC a local file for the user's run. In the second card, the command BEGIN executes a procedure named MTFLDAT which is found in file COALPRC.

6.3.5 Generation of Compilation Listing

To generate a compilation listing of COALM, include the following procedure statements as cards or file lines:

```
GET,COALPRC/UN=L6016GS
BEGIN,MLSTCOD,COALPRC.
```

In the first card, the command GET makes the procedure file COALPRC a local file for the user's run. In the second card, the command BEGIN executes a procedure named MLSTCOD which is found in file COALPRC.

6.3.6 Generation of Listing of TAB3

To generate a listing of data tables in File TAB3, include the following procedure statements as cards or file lines:

```
GET,COALPRC/UN=L6016GS.
BEGIN,MLSTTB3,COALPRC.
```

In the first card, the command GET makes the procedure file COALPRC a local file for the user's run. In the second card, the command BEGIN executes a procedure MLSTTB3 which is found in file COALPRC.

6.3.7 Run with User Tables and Input Cases

The run COALM with data tables and input cases prepared by the user, include the following procedure statements as cards or file lines:

```
GET,COALPRC/UN=L6016GS.
BEGIN,MUSRTAB,COALPRC,I=FILNAM.
```

In the first card, the command GET makes procedure file COALPRC a local file for the user's run. In the second card, the command BEGIN executes a procedure MUSRTAB which is found in file COALPRC. FILNAM is the name of the user's file containing input cases. This file may be on disc, or it may be the file created when input cards or lines are read into the computer with the job control deck. The first input case of the file

will contain any tables the user wishes to substitute for already existing tables in TAB3. For table format, see Section 5.2. Subsequent cases in the run should contain input for plant calculations as explained in Section 3.

6.4 RESOURCES REQUIRED TO EXECUTE PROCEDURES

Table 6-3 indicates the computer resources required to execute principal COALM procedures.

Table 6-3

COMPUTER RESOURCES REQUIRED TO EXECUTE COALM PROCEDURES

Procedure Executed	Words of Core	Central Processor Time, Seconds	Billing Units	Input/ Output Data Blocks (1)
Run COALM with EXAMPLM as input	102,000	12	15	47
Compile and list COALM	63,000	92	64	900
Generate File TAB4 from File TAB3	102,000	41	31	86

(1) An input/output data block contains 1280 characters

Section 7

ERROR PROCESSING

7.1 INPUT EDITING ERROR MESSAGES

Table 7-1 lists and interprets error messages that assist in assuring integrity of the input data. The input editing is performed by the program during a run. The occurrence of an error message indicates that the input should be corrected and a new run submitted.

7.2 CALCULATION ERROR MESSAGES

Table 7-2 lists and interprets the error messages that may occur during calculations. Execution is not terminated when these messages occur.

Table 7-1

INPUT ERROR MESSAGES

Message	Interpretation
In free error character, n, "string"	The nth character in "string" cannot be interpreted
Error - cannot process word n on the above card	The nth word on the input card cannot be interpreted
Error - word n on the above card should be numeric	Self explanatory
Error - word n on the above card should be alphabetic	Self explanatory
Error - word n on the above card is missing	Self explanatory
More than 10 plants, data ignored	Haul data has been provided for more than 10 decentralized plants. Only the data for the first 10 plants will be retained
More than 50 pipes, data ignored	Distribution data has been provided for more than 50 pipe segments. Only the data for the first 50 will be retained
Error - schedule values do not add up to 100 percent	The percents of spending during construction years do not total 100 percent. The life cycle costs will be erroneous

Table 7-2

CALCULATION ERROR MESSAGES

Message	Interpretation
Error - more than 100 iterations for insulation calculation for segment n, TINSUL = r	The routine calculating the heat loss of segment n has not converged. The last nonconverged value will be used

Section 8

TEST PROCEDURES

COALM was tested and verified by the following two test runs, which may be reproduced by the user:

- XMPLMF - a test run to demonstrate all major program features and verify calculations with coal mixture fuels
- TABFLO - a more extensive test run to demonstrate function of all data tables and verify agreement with data base flows and costs

8.1 TEST RUN XMPLMF

Cases in Test Run XMPLMF are described in Table 8-1. The objectives of Test Run XMPLMF are to:

- Demonstrate agreement with a three-case hand calculation presented in Section 10 of Reference 2-1 for the Navy base configuration of Figures 1-1 and 1-2 of this manual
- Demonstrate agreement with coal mixture fuel system conceptual designs in Section 6 of Reference 2-3

Module costs calculated in Test Run XMPLMF agree within 3 percent with those in the hand calculation in Section 10 of Reference 2-1. This is consistent with the accuracy of the costs calculated by the computer and hand methods. The computer method employs a least squares fit equation which approximates the costs of almost all data tabulated to within 2 percent. Hand interpolated costs of Section 10 of Reference 2-1 do not have greater accuracy.

Flows calculated in Test Run XMPLMF agree within 1 percent with those in the hand calculation of Section 10 of Reference 2-1. Since some of the flows in the hand calculation were computed approximately, the computer calculated flows can be considered more accurate.

Table 8-1

CASES AND FEATURES VERIFIED IN TEST RUN XMPLMF

Case in Test Run	Features Verified	Reference Data or Calculation
600,000 lb/hr Central plant	• Plant costs • Piping costs	Central plant of Section 10 of Reference 2-1
600,000 lb/hr Decentralized plant	• Individual boiler costs • Hauling costs	Decentralized plant of Section 10 of Reference 2-1
600,000 lb/hr Cogeneration plant	• Cogeneration	Cogeneration plant of Section 10 of Reference 2-1
400,000 lb/hr Coal-oil mixture plant	• Coal-oil mixture flows • Plant costs	Coal-oil mixture plant of Section 6 of Reference 2-3
400,000 lb/hr Coal-water mixture plant	• Coal-water mixture flows • Plant costs	Coal-water mixture plant of Section 6 of Reference 2-3

Coal mixture fuel plant module costs calculated in Test Run XMPLMF agree within 3 percent of those in Section 6 of Reference 2-3.

Mixture fuel system flows calculated in Test Run XMPLMF were adjusted to agree exactly with the flows in Section 6 of Reference 2-3.

8.2 TEST RUN TABFLOW

Cases in Test Run TABFLO are described in Table 8-2. Correct function of all cost data tables was achieved. Costs agreed within 2 percent of tabulated values. Calculated coal and scrubber flows agreed within 0.05 percent of reference tabulations.

8.3 EXECUTION OF TEST RUNS

A reader interested in using COALM is urged to reproduce Test Run XMPLMF and examine the output. Also, the reader may wish to reproduce Test Run TABFLO. The instructions to obtain such runs are provided in Section 6.

Table 8-2

CASES AND FEATURES VERIFIED IN TEST RUN TABFLO

Cases in Test Run	Features Verified	Reference Data
Boiler and Coal Handling Cases (400,000 lb/hr Plant): a. Centralized b. Decentralized	Function of Boiler and Coal Handling Cost Tables; Coal handling flows	Reference 2-1: Tables 4-1, 7-3, 7-4, 7-5, 7-6, and 7-7 Reference 2-3: Tables A-2 and A-3
Cogeneration Cases (400,000 lb/hr Plant): a. Noncondensing b. Condensing c. Condensing Peak shaving	Function of Cogeneration Cost Tables; Cogeneration flows	Reference 2-1: Tables 4-2, 9-2, and 9-4 Reference 2-3: Tables B-1 and B-2
Scrubber Type Cases (400,000 lb/hr Central Plant, 3.39% S Coal): a. Double alkali with solid waste b. Limestone with solid waste c. Lime with solid waste d. Soda liquor with solid waste e. Soda liquor with liquid waste	Scrubber flows	Reference 2-3: Table A-10
Coal Sulfur Level Cases with Solid Waste (400,000 lb/hr Plant): a. 0.5% S Centralized b. 0.5% S Decentralized c. 2% S Centralized d. 2% S Decentralized e. 4% S Centralized f. 4% S Decentralized	Function of Pollution Control Cost Tables	Reference 2-2: Tables D-1 and D-2 Reference 2-3: Tables A-4, A-5, and A-6
Coal Sulfur Level Cases with Liquid Waste (400,000 lb/hr Plant): a. 2% S Centralized b. 2% S Decentralized c. 4% S Centralized d. 4% S Decentralized	Function of Liquid Waste Pollution Control Cost Tables	Reference 2-3: Tables A-1, A-2, A-7, and A-8

Section 9

CODE DESCRIPTION

This section describes the code of COALM and includes the following topics:

- Hierarchy diagram
- Subroutine descriptions
- Logic flow diagrams
- Common blocks
- Files

9.1 HIERARCHY DIAGRAM

Figure 9-1 is a hierarchy diagram for COALM. The diagram indicates the calling hierarchy of subroutines and functions. The executive routine is COALM. Routine COALM calls subroutines below it that are connected to it by solid lines. These subroutines in turn may call other subroutines or functions further below, etc., down to four levels of subordination. On the diagram, rectangles are used for the executive routine, block data, and subroutines. Ovals are used for functions.

During a run COALM calls subroutines from left to right along the diagram. The subroutines called by COALM fall into the following six groups:

- The message routine
- Table input routines
- Case run input routines
- Engineering calculation routines
- Financial analysis routines
- The table listing routine

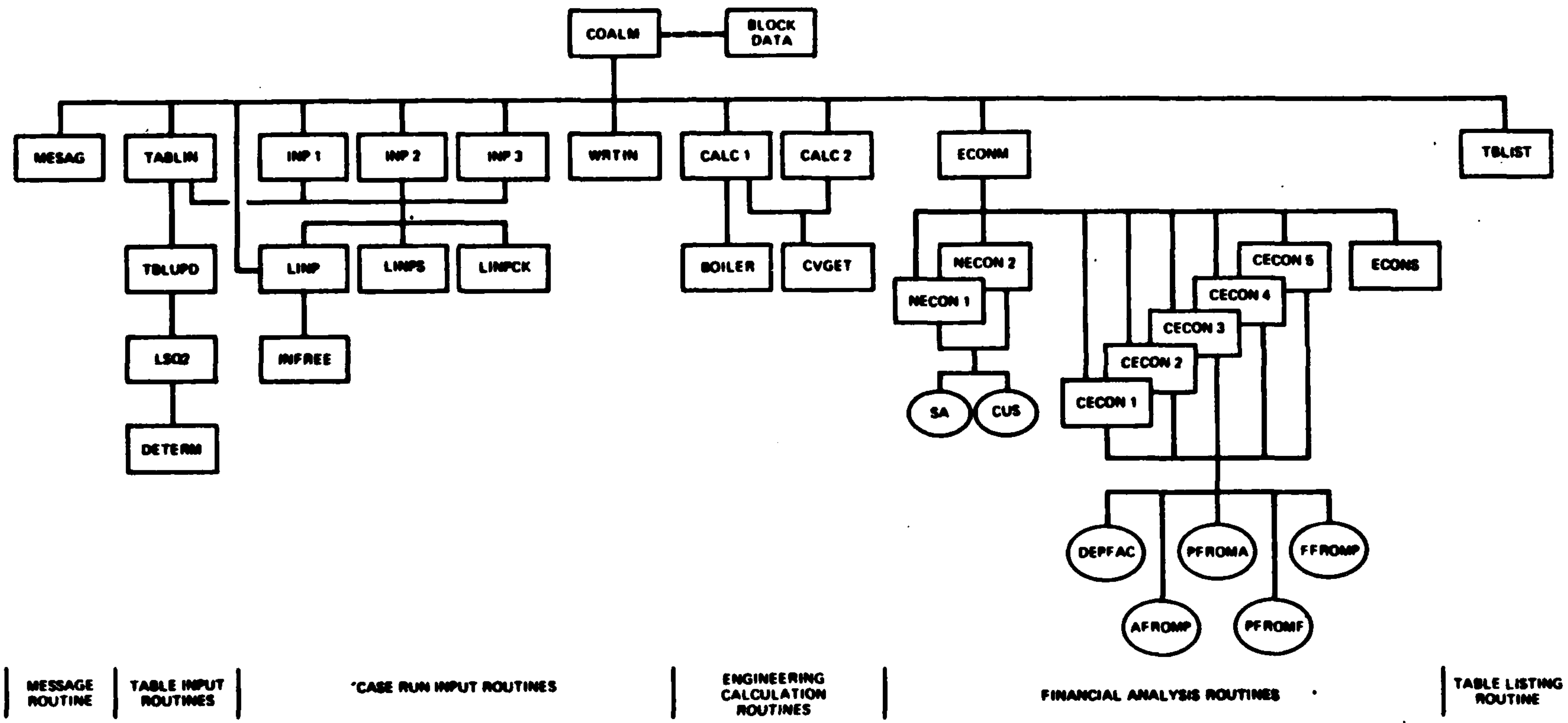


Figure 9-1 COALM HIERACHY DIAGRAM

9.2 SUBROUTINE DESCRIPTIONS

The subroutines and functions in the program are described briefly below.

9.2.1 The Message Routine

MESAG writes an identification block on the front page of each program run.

9.2.2 Table Input Routines

TABLIN reads table input data to be used to create an updated version of data table file TAB4. TBLUPD produces the new TAB4 either from the input data tables or from a combination of the input data tables and the previous version of TAB4. LSQ2 calculates least squares fit coefficients for data tables. DETERM assists LSQ2 by evaluating determinants.

9.2.3 Case Run Input Routines

INP1 reads engineering input data and stores it in internal variables. INP2 reads economic data on schedule and Navy financial parameters. INP3 reads comparison data and commercial data. WRTIN writes the interpretive echo of the case input data.

Four utility routines assist input interpretation. LINP examines each new line of input to determine whether it is a section declaration. INFREE actually reads each new line character by character and separates words from numbers. LINPS compares input words with expected key words within each section of data. LINPCK checks whether a variable is numeric or alphanumeric.

9.2.4 Engineering Calculation Routines

CALC1 calculates plant flows and module costs. BOILER provides steam generation and pollution control costs of individual boilers. CALC2 performs steam transmission calculations and prints a summary of capital and operating costs. CVGET retrieves module costs from TAB4.

9.2.5 Financial Analysis Routines

ECONM serves as an executive routine to manage calls to the financial routines. NECON1 calculates present values and levelized costs for a Navy financed/Navy operated venture. NECON2 calculates year-by-year costs and benefits for such an all-Navy venture. SA calculates the Navy discount factor for a one-time cash flow. CUS calculates the Navy cumulative uniform series discount factor for a series of annual cash flows.

Commercial economic calculations are carried out by 11 subroutines and functions. CECON1 calculates private venture minimum revenue requirements. CECON2 calculates private or third party investor cash flows during the construction period. CECON3 calculates third party investor cash flows during the operating period. CECON4 calculates private venture cash flows during the operating period. CECON5 calculates Navy cash flows during the operating period for a third party financed/Navy operated venture. ECONS prints summary reports.

Five utility functions assist the commercial economic calculations. DEPFAC calculates the fraction of capital depreciated each year. AFROMP calculates the factor to form an annuity from a present value. PFROMA calculates the factor to form a present value from an annuity. PFROMF calculates the factor to form a present value from a future value. FFROMP calculates the factor to form a future value from a present value.

9.2.6 Table Listing Routine

TBLIST lists tables that were input or tables called for by the list command.

9.3 LOGIC FLOW DIAGRAM

This section provides logic flow diagrams for the engineering calculations in COALM. Summary diagram Figure 9-2 shows that the calculations are divided into four segments. Figure 9-3 provides the logic for Segment 1, which calculates steam and power generation and

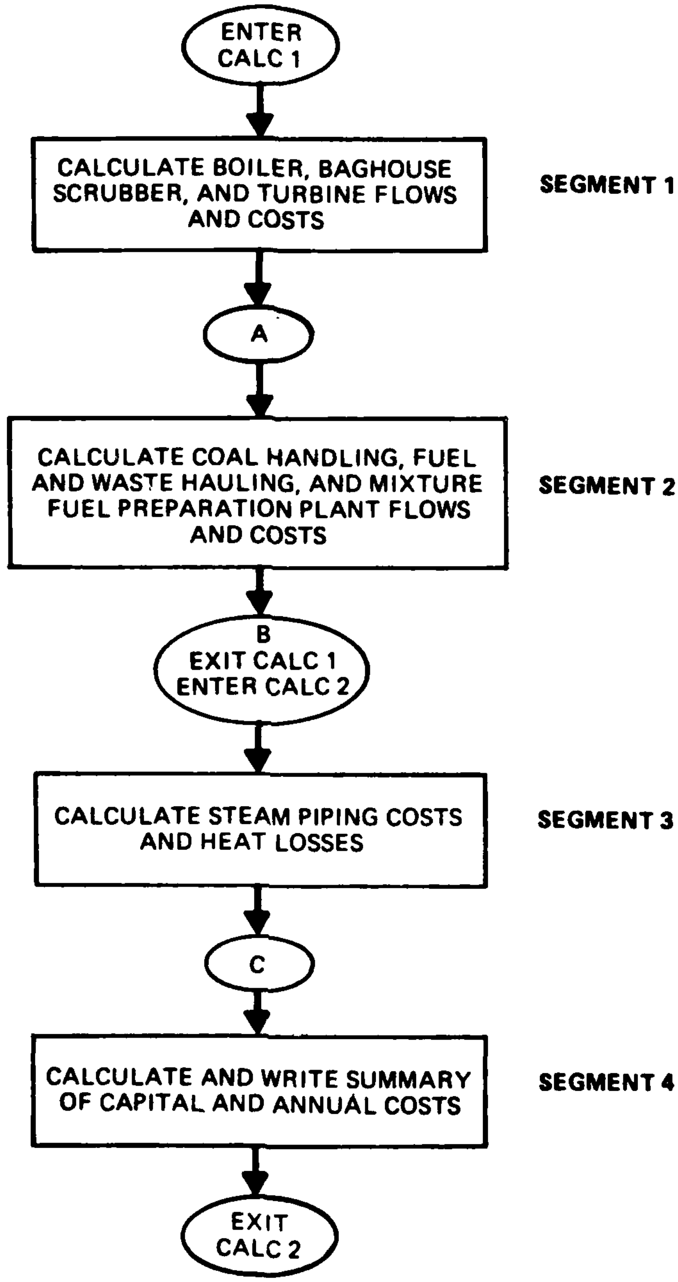


Figure 9-2 SUMMARY LOGIC FLOW DIAGRAM FOR ENGINEERING CALCULATIONS

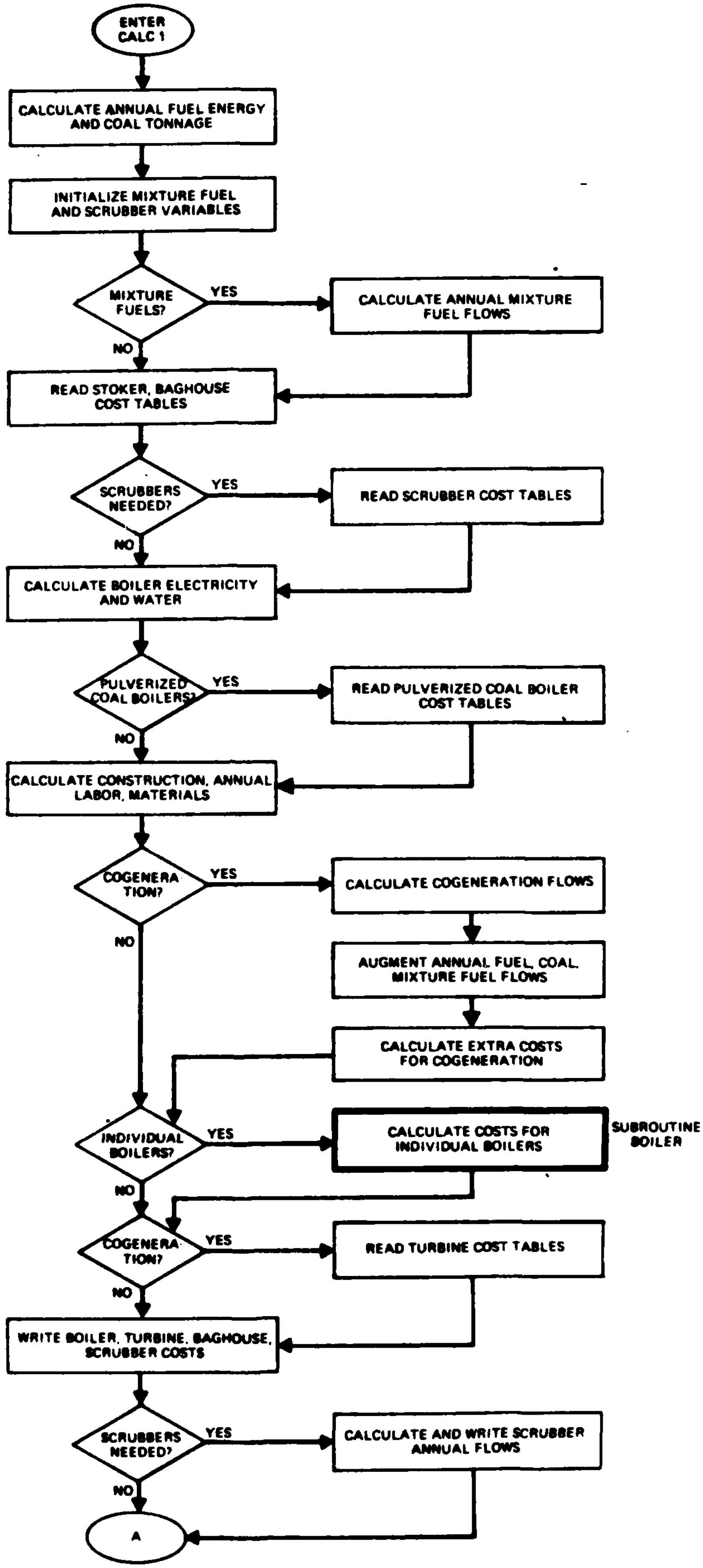


Figure 9-3 LOGIC FLOW DIAGRAM FOR SEGMENT 1 ENGINEERING CALCULATIONS

pollution control flows and costs. Figure 9-4 provides the logic for Segment 2, which calculates coal handling, fuel and waste handling, and mixture fuel preparation flows and costs. Figure 9-5 provides the logic for Segment 3, which calculates steam piping costs and heat losses. Figure 9-6 provides the logic for Segment 4, which calculates and writes a summary of capital costs and annual operating and maintenance costs.

Logic flow diagrams describing the financial analysis routines are provided in Reference 2-5, the user's manual for the Phase I computer program.

9.4 COMMON BLOCKS

COALM has a number of blocks of common variables which are shared by program routines. Incidence Table 9-1 lists the common blocks and routines and indicates where they coincide.

9.5 FILES

COALM is composed of a number of files available to the user. These are stored on tape for use with Control Data Corporation's Western Cybernet Center's computer designated KWA in Sunnyvale, California. The COALM files and their functions are listed in Table 9-2. The read-only program tape containing these files is designated COLCONV, and is assigned to NCEL user number L6016GS. The files are retrieved from this tape by the procedures for running the program which are described in Section 6. Users should contact the NCEL Data Processing Center if they desire to use the tape and files in a way other than specified in the procedures of Section 6.

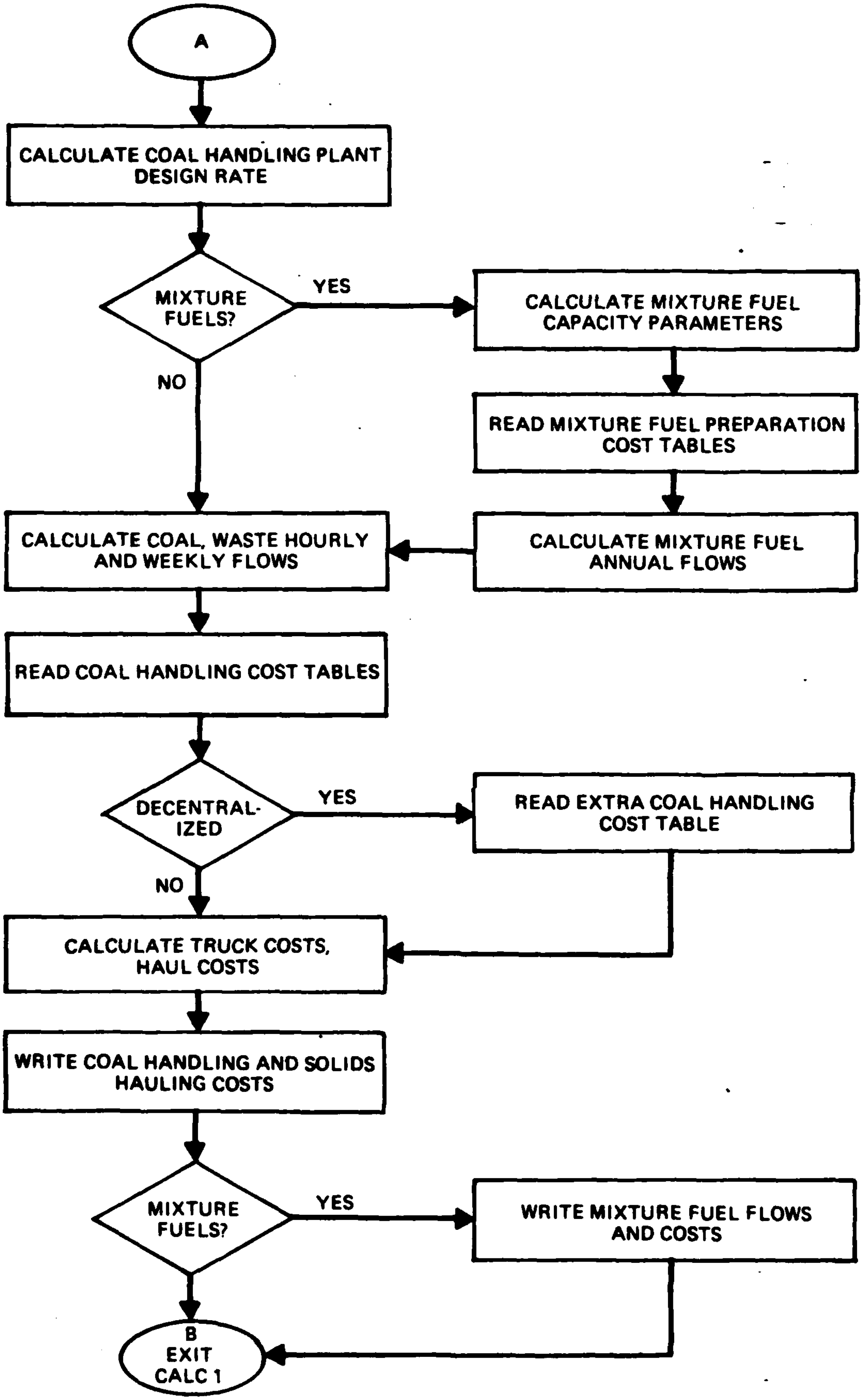


Figure 9-4 LOGIC FLOW DIAGRAM FOR SEGMENT 2 ENGINEERING CALCULATIONS

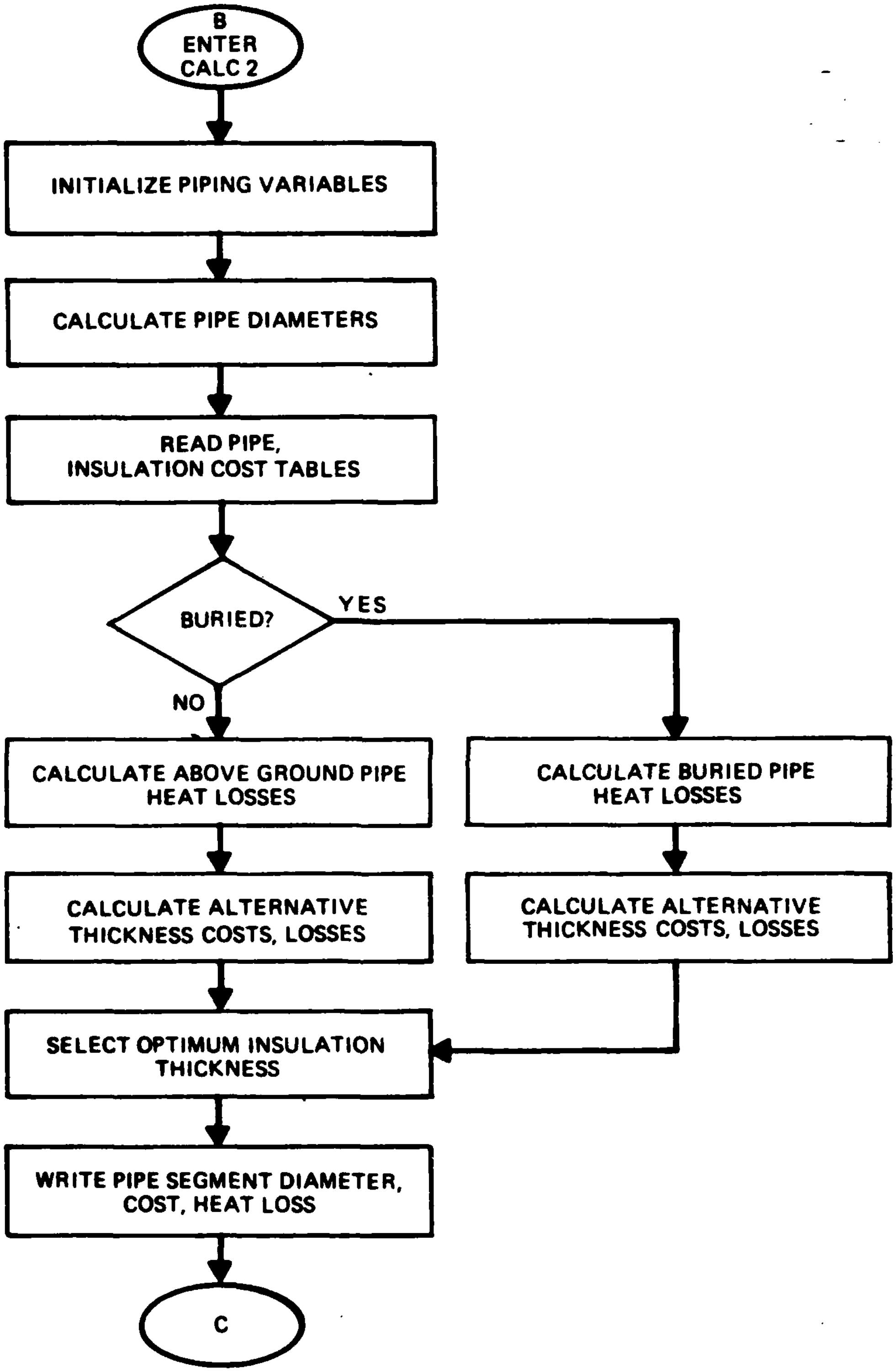


Figure 9-5 LOGIC FLOW DIAGRAM FOR SEGMENT 3 ENGINEERING CALCULATIONS

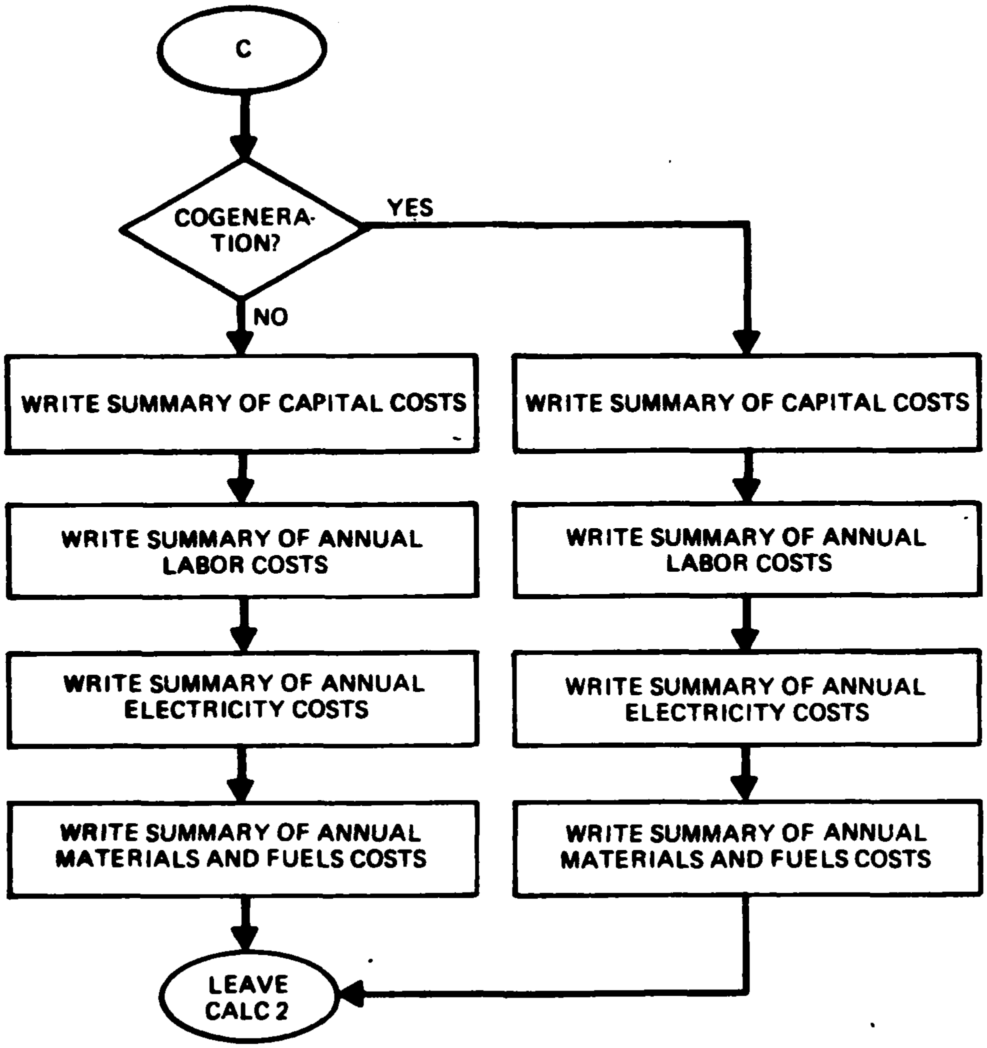


Figure 9-6 LOGIC FLOW DIAGRAM FOR SEGMENT 4 ENGINEERING CALCULATIONS

Table 9-1

COALM COMMON BLOCK INCIDENCE TABLE

Routine	BSECOM	COAL1	COAL2	COAL3	CTBCOM	CXCOMM	ESTATS	INFCOM	LINPCM	MIXCOM	SECTCM	SYSCOM	TABCOM	TNAMCM	TTLCOM	WRDCOM
COALM		X	X	X	X	X		X	X	X	X	X	X	X	X	X
BLOCK DATA		X	X	X	X	X				X	X	X		X		
BOILER		X	X	X						X		X		X	X	
CALC1		X	X	X						X		X		X	X	
CALC2		X	X	X						X		X		X	X	
CECON1		X	X	X			X					X			X	
CECON2	X	X	X	X			X					X			X	
CECON3	X	X	X	X			X					X			X	
CECON4	X	X	X	X			X					X			X	
CECON5		X	X	X			X					X			X	
CVGET												X	X		X	
DETERM																
ECONM	X	X	X	X			X			X		X		X	X	
ECONS		X	X	X			X					X			X	
INFREE												X				X
INP1		X	X	X	X			X	X	X	X	X			X	
INP2		X	X	X		X		X	X	X	X	X			X	
INP3	X	X	X	X			X	X	X		X	X			X	
LINP									X			X				X
LINPS									X			X				X
LINPCK									X			X				X
LSQ2																
MESAG												X				
NECON1		X	X	X								X			X	
NECON2	X	X	X	X			X					X			X	
TABLIN								X	X		X	X	X			X
TBLIST												X	X		X	
TBLUPD												X	X		X	
WRTIN	X	X	X	X	X	X	X	X	X	X	X	X			X	

Table 9-2

NAMES AND FUNCTIONS OF COALM FILES ON TAPE COLCONV

File Name	File Functions
COALMR	Program machine-language relocatable code
TAB4	Machine-language file of data tables
COALM	Program FORTRAN5 source code
TAB3	User-readable data tables in input language
EXAMPLM	Input data file for example case in Appendix A
XMPLMF	Input data file of 6-case test run described in Table 8-1
TABFLO	Input data file of 20-case test run described in Table 8-2

REFERENCES

2-1 Coal Fired Boilers at Navy Bases, Bechtel National, Inc., San Francisco, California, CEL Contract Report CR 79.012, Navy Energy Guidance Study, Phase II and III, May 1979.

2-2 Flue Gas Desulfurization at Navy Bases, Bechtel National, Inc., San Francisco, California, CEL Contract Report CR 80.023, Navy Energy Guidance Study, Phase IV, August 1980.

2-3 Coal Mixture Fuels at Navy Bases, Bechtel Group, Inc., San Francisco, California, Draft NCEL Contract Report, Contract N62474-82-C-8290, Engineering Services for Coal Conversion Guidance, Phase II, July 1983.

2-4 A Coal-Use Economics Methodology for Navy Bases, Bechtel Group, Inc., San Francisco, California, Draft NCEL Contract N62474-82-C-8290, Engineering Services for Coal Conversion Guidance, Phase I, July 1983.

2-5 COALR - Coal Conversion Cost Reformulation Program: User Manual, Bechtel Group, Inc., San Francisco, California, Draft NCEL Contract Report, Contract N62474-82-C-8290, Engineering Services for Coal Conversion Guidance, Phase I, September 1983.

2-6 Comparison of Coal Energy Conversion Technologies at Navy Bases, Bechtel Group, Inc., San Francisco, California, Draft NCEL Contract Report, Contract N62474-82-C-8290, Engineering Services for Coal Conversion Guidance, Phase III, July 1983.

3-1 Coal Conversion Cost Computer Program, Peter F. Loftus Corporation, Pittsburgh, Pennsylvania, Draft NCEL Contract Report, Contract N62474-81-C-9409, September 1982.

EXAMPLE OUTPUT

Appendix A

LIST OF TABLES

Table A-1

INPUT DATA ECHO

```
                         INPUT DATA LISTING                         PAGE   1
* 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL
*
PLANT DATA
*
PRESS 300 PEAK LOAD 600 EFF .8 LOAD FACTOR .40
*     PSIA      1000-LB/HR
DECENTRALIZED
*
OIL
SGCOAL 1.4 SGLIQUID 0.95 SULFUR 1.0 ASH 0.1 BTU 18800
* SPECIFIC GRAVITIES          WT %     WT %     BTU/LB
*
BOILERS 4
LP 1 CAPACITY 300      * 1000-LB/HR
LP 2 CAPACITY 150      * 1000-LB/HR
LP 3 CAPACITY  75      * 1000-LB/HR
LP 4 CAPACITY  75      * 1000-LB/HR
*
COAL DATA              * DISPLAY YEAR PRICE
*
SULFUR 3 ASH 15 BTU 11534 PRICE 30 DIR 5
*     WT %   WT %     BTU/LB     $/TON  %/YR
*
UTILITY DATA           * DISPLAY YEAR PRICES
*
MANHOURS    20         * $/HR
ELECTRIC .025 DIR  6   * $/KWH        , %/YR
GAS        3.20 DIR 10 * $/1000-SCF   , %/YR
STEAM      8.00 DIR  6 * $/1000-LB    , %/YR
OIL         .46 DIR  8 * $/GALLON     , %/YR
WATER       .30        * $/1000-GAL
LIME        50         * $/TON
SODA        70         * $/TON
*
SCRUBBER TYPE
*
DOUBLE ALKALI
*
HAUL DATA
*
OFF 50  * MILES
*
* 1000-LB/HR      MILES
1 LOAD 300 DISTANCE 5
2 LOAD 150 DISTANCE 4
3 LOAD  75 DISTANCE 4.5
4 LOAD  75 DISTANCE 5
*
DISTRIBUTION DATA
*
TAMB 45 * F
*       FT          LB/HR        PSIA       PSIA              F
LENGTH  2500 FLOW  15000 INLET 300 EXIT  30 TSTEAM 258 ABOVE
*
```

```
ECONOMIC DATA
*
STARTUP YEAR 1981 MONTH 5
DISPLAY YEAR 1978 MONTH 5
COST INDEX 216.8 CHEM-ENG * DISPLAY YEAR VALUE
SCHEDULE 63,37          * % OF CONSTRUCTION SPENT EACH YEAR
*                         COUNTING BACKWARDS FROM STARTUP
LIFE 25 SALVAGE 0 DISCOUNT 10    * NAVY CONSTANT DOLLAR
* YEARS     $1000       %/YR       DISCOUNT RATE
*
COMPARISON DATA
*
BURN OIL
*
COMMERCIAL DATA
*
INFLATION 6 * %/YR
DEBT 30 INTEREST 11 RETURN 18    * CURRENT DOLLAR RATES
*      %        %/YR       %/YR
THIRD PARTY    LEASE LIFE 15     * YEARS
INCOME TAX RATE 50 CREDIT 10
* % TAXABLE INCOME, % OF INVESTMENT
PROPERTY TAX PERCENT 2           * % OF TOTAL CAPITAL
DEPRECIATION ACRS LIFE 5         * YEARS
* ACCELERATED CAPITAL RECOVERY SYSTEM
*
END JOB
```

INDIVIDUAL BOILERS

NUMBER OF BOILERS: 4

BOILER NUMBER	PRESSURE TYPE	STEAM CAPACITY (1000 LB/HR)
1	LOW PRESSURE	300.
2	LOW PRESSURE	150.
3	LOW PRESSURE	75.
4	LOW PRESSURE	75.

COALM V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

PLANT DATA

PRESSURE (PSI)	PEAK LOAD (1000-LB/HR)	EFFICIENCY	LOAD FACTOR	
300.	600.00	.800	.400	DECENTRALIZED

COAL MIXTURE FUEL DATA

FUEL TYPE	MIX CAPACITY FRACTION	DAYS STORAGE
COAL-OIL	.400	36.0

COAL DATA

SULFUR (WT PERCENT)	ASH (WT PERCENT)	HIGHER HEATING VALUE (BTU/LB)	DELIVERED PRICE ($/TON)	DIR (PERCENT)	SPECIFIC GRAVITY
3.0	15.0	11534.0	30.0	5.00	1.400

OIL DATA

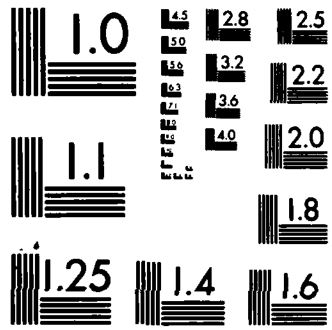
SULFUR (WT PERCENT)	ASH (WT PERCENT)	HIGHER HEATING VALUE (BTU/LB)	SPECIFIC GRAVITY
1.00	.10	18600.0	.950

UTILITY DATA

	RATE (DISPLAY YEAR DOLLARS)	DIFFERENTIAL INFLATION RATE (PERCENT/YEAR)
ELECTRIC	$ .0250 /KWH	6.00
MANHOURS	$ 20.0000 /HOUR	
WATER	$ .3000 /1000-GAL	
GAS	$ 3.2000 /1000-CU FT	10.00
STEAM	$ 6.0000 /1000-LBS	6.00
OIL	$ .4800 /GALLON	8.00
LIME	$ 50.0000 /TON	
SODA	$ 70.0000 /TON	

AD-A140 515 A COAL-USE ECONOMICS METHODOLOGY FOR NAVY BASES PHASE II OF ENGINEERING S..(U) BECHTEL GROUP INC SAN FRANCISCO CA A I MCCONE ET AL. FEB 84 NCEL-RR-84.002 3/3

UNCLASSIFIED N62474-82-C-8290 F/G 10/1 NL



MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS-1963-A

DALM V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

--- SCRUBBER TYPE - DOUBLE ALKALI

HAULING DISTANCES (MILES)

COAL	ASH	SLUDGE	OFF BASE
0.00	0.00	0.00	50.00

DECENTRALIZED BOILER STATIONS

PLANT	LOAD (1000-LB/HR)	DISTANCE (MILES)
1	300.00	5.00
2	150.00	4.00
3	75.00	4.50
4	75.00	5.00

DISTRIBUTION DATA

45.0 DEG AMBIENT TEMPERATURE

SEGMENT	LENGTH (FEET)	FLOW (LB/HR)	INLET P (PSI)	EXIT P (PSI)	STEAM T (DEG-F)	
1	2500.	15000.	300.	30.	358.	ABOVE

COALM V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

ECONOMIC DATA

DISPLAY DATE - MAY 1978

STARTUP DATE - MAY 1981

SCHEDULE (PERCENT) - 63.00 37.00

DISPLAY YEAR COST INDEX - 216.80 INDEX TYPE - CHEM-ENG

BASE YEAR INDEX - 216.80

LIFE (YEARS)	SALVAGE (DISPLAY YEAR DOLLARS)	DISCOUNT RATE (PERCENT/YEAR)
25.0	0.	10.00

COMMERCIAL DATA: THIRD PARTY FINANCING

INFLATION RATE:	6.00 PERCENT PER YEAR
DEBT FRACTION:	30.00 PERCENT
INTEREST RATE:	11.00 PERCENT PER YEAR
RETURN ON EQUITY:	18.00 PERCENT PER YEAR
INCOME TAX RATE:	50.00 PERCENT
TAX CREDIT:	10.00 PERCENT
PROPERTY TAX AND INS.:	2.00 PERCENT OF TOTAL CAPITAL REQUIREMENT
ACRS DEPRECIATION LIFE:	5 YEARS
LEASE LIFE:	15 YEARS

BASE CASE IS OIL-FIRED STEAM PLANT

Table A-2

FLOWS, CAPITAL COSTS, AND FIRST YEAR COSTS

11.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

INDIVIDUALLY PRICED BOILER PLANTS

BOILER NUMBER	PRESSURE TYPE	BOILER CONSTRUCTION ($1000)	BOILER AND BAGHOUSE ANNUAL LABOR (1000 MHRS)	BOILER AND BAGHOUSE ANNUAL MATERIAL ($1000)	SCRUBBER AND BAGHOUSE CONSTRUCTION ($1000)	SCRUBBER ANNUAL LABOR (1000 MHRS)	SCRUBBER ANNUAL MATERIALS ($1000)
1	LP	7455.	37.	267.	5877.	18.	167.
2	LP	4535.	22.	161.	3329.	15.	104.
3	LP	2750.	14.	98.	2084.	13.	71.
4	LP	2750.	14.	98.	2084.	13.	71.
TOTAL		17489.	87.	623.	13374.	59.	413.

COALM V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

BOILER PLANT PERFORMANCE

ANNUAL ENERGY INPUT 2628000. MILLION BTU

ANNUAL COAL CONSUMPTION 43318. TONS/YEAR

PLANT CAPACITY 600.000 THOUSAND POUNDS PER HOUR

ANNUAL LOAD FACTOR 40. PERCENT

BOILER AND POLLUTION CONTROL TOTAL CONSTRUCTION COST

BOILER RETROFIT $ 1749. THOUSAND

POLLUTION CONTROL $ 13374. THOUSAND

BOILER AND BAGHOUSE ANNUAL REQUIREMENTS

LABOR 66.568 THOUSAND HOURS

ELECTRICITY 6307.200 THOUSAND KWH

WATER 2680.560 THOUSAND GALLONS

OTHER MATERIALS $ 623.015 THOUSAND

SCRUBBER LABOR, UTILITY AND WASTE REQUIREMENTS

SCRUBBER TYPE - DOUBLE ALKALI

SULFUR NEUTRALIZED PER YEAR 944. TONS

	ANNUAL OPERATION	UNIT COST	COST (THOUSANDS)
MANHOURS	60.647 1000-HOURS	$ 20.00 /HOUR	$ 1213.
LIME	2044. TONS	$ 50.0000 /TON	$ 102.
SODA	188. TONS	$ 70.0000 /TON	$ 13.
WATER	18562. 1000-GAL	$ .3000 /1000-GAL	$ 6.
STEAM	50904. 1000-LBS	$ 8.0000 /1000-LBS	$ 407.
ELECTRIC	1908.482 1000-KWH	$ .0250 /KWH	$ 48.
SLUDGE	8653. TONS		
OTHER MATERIAL COSTS			$ 414.

JALM V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

COAL AND WASTE HANDLING

PEAK COAL RATE	12.4	TONS/HOUR
DESIGN PEAK COAL RATE	9.2	TONS/HOUR
DESIGN PEAK COAL RATE	1538.4	TONS/WEEK
STOCK PILE	9889.9	TONS
PEAK ASH RATE	313.6	TONS/WEEK
PEAK SLUDGE RATE	416.0	TONS/WEEK

COAL HANDLING FACILITY

CONSTRUCTION COSTS	$	1889.	THOUSAND
OPERATING MANHOURS		10.865	THOUSAND HOURS
ELECTRICITY		168.073	THOUSAND KWH
OPERATING MATERIALS	$	108.	THOUSAND

DECENTRALIZED HANDLING AND HAULING

EXTRA CONSTRUCTION COSTS	$	61.	THOUSAND
ANNUAL MANHOURS		3.769	THOUSAND HOURS
AVERAGE DISTANCE FROM CENTRAL FACILITY		5.	MILES
NUMBER OF TRUCKS REQUIRED		2.	TRUCKS
CAPITAL COST PER TRUCK	$	80.	THOUSAND
FUEL USED PER YEAR		32055.	GALLONS
ANNUAL FUEL COST	$	15.	THOUSAND
ANNUAL MAINTENANCE, LABOR AND MATERIALS	$	50.	THOUSAND

COALM V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

AVERAGE COAL RATE	4.9	TONS/HOUR
AVERAGE ASH RATE	.7	TONS/HOUR
AVERAGE SLUDGE RATE	1.0	TONS/HOUR
COST OF OFF-BASE HAULING $	134.	THOUSAND

JALM V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

COAL MIXTURE FUEL PREPARATION FACILITY

TYPE OF MIXTURE FUEL		COAL-OIL	
PEAK CMF DEMAND		24.7	TONS PER HOUR
DESIGN CMF MIXING		9.9	TONS PER HOUR
STORAGE:	DAYS AT PEAK CMF	36.	
	BARRELS	107736.	
CONSTRUCTION COSTS	MIX FACILITY $	2009.	THOUSAND
	CMF STORAGE $	933.	THOUSAND
ANNUAL LABOR:	MIX FACILITY	16.786	THOUSAND HOURS
	CMF STORAGE	4.530	THOUSAND HOURS

ANNUAL REQUIREMENTS

COAL	43317.729	TONS
OIL	10932.494	1000 GALLONS
WATER	0.000	1000 GALLONS
ELECTRICITY	961.944	1000 KWH
HEATING STEAM	7326.024	1000 LB
NATURAL GAS	13471.814	1000 SCF

FIRST YEAR COSTS

MATERIALS, SUPPLIES:	MIX FACILITY $	96.444	THOUSAND
	CMF STORAGE $	46.895	THOUSAND
ELECTRICITY	$	24.049	THOUSAND
HEATING STEAM	$	53.608	THOUSAND
NATURAL GAS	$	43.110	THOUSAND

COALM V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

STEAM TRANSMISSION SYSTEM COSTS

SEGMENT	LENGTH (FT)	NOM. DIAM. (IN)	FLOW (LB/HR)	INLET PRESSURE (PSI)	OUTLET PRESSURE (PSI)	INSUL. THICK. (IN)	HEAT LOSS PER FOOT (BTU/FT)	COST PER FOOT ($/FOOT)	TOTAL COST (1000-$)	TOTAL HOURLY HEAT LOSS (MILLION BTU)	TI (DEG F)
1	2500.	4.	15000.	300.	30.	2.	106.16	88.33	221.	.265	51.

TOTAL STEAM TRANSMISSION COSTS 221. THOUSAND DOLLARS

TOTAL STEAM TRANSMISSION HEAT LOSS .265 MILLION BTU PER HOUR

ALM V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

COST SUMMARY (THOUSANDS OF DOLLARS)

CONSTRUCTION COSTS			
BOILER RETROFIT	1749.		
POLLUTION CONTROL	13374.		
COAL HANDLING, TRUCKS	2111.		
MIXTURE FUEL PREPARATION	2947.		
STEAM TRANSMISSION	221.		
TOTAL		20401.	
STARTUP COSTS		2220.	
TOTAL LABOR COST			
MANHOURS - BOILERS, BAGHOUSES	86.568		THOUSAND HOURS
SCRUBBER	60.647		THOUSAND HOURS
COAL HANDLING	10.865		THOUSAND HOURS
MIXTURE FUEL PREPARATION	21.316		THOUSAND HOURS
DECENTRALIZED HANDLING/HAULING	3.709		THOUSAND HOURS
TOTAL MANHOURS	183.155		THOUSAND HOURS
TIMES 20.00 PER HOUR		3663.	
TOTAL ELECTRICITY COSTS			
KWH - BOILERS, COAL HANDLING	6475.273		THOUSAND KWH
SCRUBBER	1908.482		THOUSAND KWH
MIXTURE FUEL PREPARATION	961.944		THOUSAND KWH
TOTAL KWH	9345.699		THOUSAND KWH
TIMES .0250 PER KWH		234.	

COST SUMMARY (THOUSANDS OF DOLLARS)

TOTAL OPERATING MATERIAL COSTS		
BOILERS, POLLUTION CONTROL	1037.	
LIME	102.	
LIMESTONE	0.	
SODA	13.	
WATER FOR BOILERS, SCRUBBERS	6.	
STEAM	407.	
COAL HANDLING	158.	
OFF-BASE HAULING	134.	
DECENTRALIZED HANDLING/HAULING	50.	
MIXTURE FUEL PREPARATION	143.	
CMF STEAM	59.	
CMF NATURAL GAS	43.	
CMF WATER	0.	
TOTAL		2153.
OIL-COST-SENSITIVE OPERATING COSTS		
FUEL FOR ON-BASE HAULING	15.	
THOUSANDS OF GALLONS OF OIL FOR CMF 10932.494		
TIMES .480 PER GAL	5248.	
TOTAL		5263.
COAL COSTS		
TONS OF COAL	43318.	
TIMES 30.00 PER TON		1300.

Table A-3

FINANCIAL ANALYSIS REPORTS

V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

NAVY PRESENT VALUES IN DISPLAY YEAR DOLLARS *

		COST (1000 $)	DISCOUNT FACTOR	PRESENT VALUE (1000 $)	UNIT PRESENT VALUE ** ($/MILLION BTU)
CONSTRUCTION	1980	7546.	.8671	6545.	.12
CONSTRUCTION	1981	12853.	.7883	10137.	.19
TOTAL CONSTRUCTION		20401.		16677.	.32
STARTUP	1981	2220.	.7883	1759.	.03
1981 - 2006					
LABOR		3663.	7.1553	26217.	.50
OPERATING + MAINTENANCE MATERIAL		1645.	7.1553	11767.	.22
ELECTRICITY		234.	14.5882	3409.	.06
GAS		43.	25.0000	1073.	.02
STEAM		466.	14.5882	6794.	.13
OIL		5263.	18.9768	99875.	1.90
COAL		1300.	12.8527	16707.	.32
TOTAL				184265.	3.51

* ALL COSTS AND PRESENT VALUES ARE REFERENCED TO THE DISPLAY DATE OF MAY 1979

** 52560. BILLION BTUS OF HEAT ARE TRANSFERRED IN 25.0 YEARS OF OPERATING LIFE

COALM V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

NAVY LEVELIZED COSTS IN DISPLAY YEAR DOLLARS *

		COST (1000 $)	LEVELIZING FACTOR	LEVELIZED COST (1000 $)	UNIT LEVELIZED COST ** $/MILLION BTU
CONSTRUCTION	1980	7548.	.1212	915.	.44
CONSTRUCTION	1981	12853.	.1102	1416.	.67
TOTAL CONSTRUCTION		20401.		2331.	1.11
STARTUP	1981	2220.	.1102	245.	.12
1981 - 2006					
LABOR		3663.	1.0000	3663.	1.74
OPERATING + MAINTENANCE MATERIAL		1645.	1.0000	1645.	.78
ELECTRICITY		234.	2.0398	476.	.23
GAS		43.	3.4939	151.	.07
STEAM		460.	2.0386	937.	.45
OIL		5263.	2.6521	13958.	6.64
COAL		1300.	1.7962	2334.	1.11
TOTAL				25757.	12.25

* ALL COSTS ARE REFERENCED TO THE DISPLAY DATE OF MAY 1978

** 2102.40 BILLION BTUS OF HEAT ARE TRANSFERRED ANNUALLY

DALR V1.0   600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

NAVY COST AND BENEFIT ANALYSIS
(THOUSANDS OF DISPLAY YEAR DOLLARS)

YEAR	CONSTRUCT COSTS	STARTUP COST	OPERATING COSTS	OPERATING BENEFITS	SAVINGS (OPERATING BENEFITS -COSTS)	PRESENT VALUE DISCOUNT FACTOR	PV* OF CONSTRUCT + STARTUP COSTS	PV OF OPERATING COSTS	PV OF SAVINGS
1980	7548.					.867	6545.		
1981	12853.	2220.				.788	11882.		
1982			14655.	11703.	-2953.	.717		10502.	-2116.
1983			15341.	12599.	-2742.	.651		9994.	-1786.
1984			16078.	13567.	-2511.	.592		9522.	-1487.
1985			16871.	14612.	-2259.	.538		9083.	-1216.
1986			17723.	15740.	-1983.	.489		8675.	-971.
1987			18641.	16958.	-1682.	.445		8294.	-749.
1988			19627.	18274.	-1353.	.405		7940.	-547.
1989			20689.	19695.	-994.	.368		7608.	-366.
1990			21831.	21229.	-602.	.334		7298.	-201.
1991			23059.	22885.	-174.	.304		7008.	-53.
1992			24382.	24674.	292.	.276		6736.	81.
1993			25805.	26605.	800.	.251		6451.	201.
1994			27336.	28691.	1354.	.228		6242.	309.
1995			28965.	30942.	1958.	.208		6017.	406.
1996			30759.	33374.	2515.	.189		5805.	493.
1997			32669.	36000.	3331.	.172		5605.	571.
1998			34726.	38835.	4109.	.156		5416.	641.
1999			36941.	41897.	4957.	.142		5237.	703.
2000			39325.	45203.	5878.	.129		5069.	758.
2001			41893.	48774.	6881.	.117		4909.	806.
2002			44658.	52629.	7970.	.107		4757.	849.
2003			47637.	56792.	9155.	.097		4613.	887.
2004			50845.	61287.	10442.	.088		4476.	919.
2005			54301.	66141.	11841.	.080		4346.	948.
2006			58023.	71383.	13360.	.073		4222.	972.
TOTAL	20401.	2220.	762799.	830489.	67689.		18427.	165855.	52.

PRESENT VALUE OF COSTS = $184282. THOUSAND
UNIT PRESENT VALUE = $ 3.51 PER MILLION BTU (PV / 52560. BILLION BTU)
LEVELIZED COST = $ 25755. THOUSAND (PV * .1398)
UNIT LEVELIZED COST = $ 12.25 PER MILLION BTU (LEVELIZED COST / 2102. BILLION BTU)
SAVINGS/INVESTMENT RATIO = .00 (PV SAVINGS / PV INVESTMENT)
DISCOUNTED PAYBACK PERIOD DOES NOT EXIST

* PV DENOTES PRESENT VALUE

COALM V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

NAVY PRESENT VALUES IN STARTUP YEAR DOLLARS *

		COST (1000 $)	DISCOUNT FACTOR	PRESENT VALUE (1000 $)	UNIT PRESENT VALUE ($/MILLION BTU)
CONSTRUCTION	1980	6990.	1.1541	10374.	.20
CONSTRUCTION	1981	15308.	1.0492	16061.	.31
TOTAL CONSTRUCTION		24298.		26437.	.50
STARTUP	1981	2644.	1.0492	2774.	.05
1981 - 2006					
LABOR		4363.	9.5237	41557.	.79
OPERATING + MAINTENANCE MATERIAL		1959.	9.5237	18653.	.35
ELECTRICITY		331.	16.3028	5403.	.10
GAS		68.	25.0000	1704.	.03
STEAM		661.	16.3028	10773.	.20
OIL		7896.	20.0507	158325.	3.01
COAL		1792.	14.7776	26477.	.50
TOTAL				292104.	5.55

* ALL COSTS AND PRESENT VALUES ARE REFERENCED TO THE STARTUP DATE OF MAY 1981

** 52560. BILLION BTUS OF HEAT ARE TRANSFERRED IN 25.0 YEARS OF OPERATING LIFE

.M V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

NAVY LEVELIZED COSTS IN STARTUP YEAR DOLLARS *

		COST (1000 $)	LEVELIZING FACTOR	LEVELIZED COST (1000 $)	UNIT LEVELIZED COST ** $/MILLION BTU
CONSTRUCTION	1980	8990.	.1212	1089.	.52
CONSTRUCTION	1981	15306.	.1102	1686.	.80
TOTAL CONSTRUCTION		24296.		2775.	1.32
STARTUP	1981	2644.	.1102	291.	.14
1981 - 2006					
LABOR		4363.	1.0000	4363.	2.08
OPERATING + MAINTENANCE MATERIAL		1959.	1.0000	1959.	.93
ELECTRICITY		331.	1.7118	567.	.27
GAS		68.	2.6250	179.	.09
STEAM		661.	1.7118	1131.	.54
OIL		7690.	2.1054	16024.	7.91
COAL		1792.	1.5517	2781.	1.32
TOTAL				30671.	14.59

* ALL COSTS ARE REFERENCED TO THE STARTUP DATE OF MAY 1981

** 2102.40 BILLION BTUS OF HEAT ARE TRANSFERRED ANNUALLY

COALR V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

THIRD PARTY FINANCED/NAVY OPERATED VENTURE:
INVESTOR CASH FLOWS DURING CONSTRUCTION PERIOD
(THOUSANDS OF DOLLARS)

	SOURCE OF FUNDS		USE OF FUNDS		TOTAL	TAX			PRESENT VALUE	
YEAR	DEBT	EQUITY	CAPITAL COST	INTEREST ON DEBT	SOURCES AND USES	SAVINGS FROM IDC DEDUCTION	TAX CREDITS	AFTER TAX EQUITY CASH FLOW	EQUITY** PORTION	TOTAL* INVESTMENT
1980	2544.	5937.	8481.	0.	8481.	0.	848.	5089.	6005.	8829.
1981	5470.	12762.	17952.	280.	18232.	140.	1647.	10986.	10986.	16175.
TOTAL	8014.	18699.	26433.	280.	26713.	140.	2495.	16075.	16991.	25005.

* PRESENT VALUE AT STARTUP BASED ON RETURN ON EQUITY = 18.00 PERCENT PER YEAR

** PRESENT VALUE AT STARTUP BASED ON WEIGHTED COST OF CAPITAL = 15.90 PERCENT PER YEAR

CALCULATION OF TAX BASIS
(THOUSANDS OF DOLLARS)

	PLANT INVESTMENT (INCLUDING STARTUP)			TAX CREDIT	
YEAR	DEPRECIABLE PORTION	TOTAL	INTEREST ON DEBT	ADJUSTMENT TO TAX BASIS	TAX BASIS
1980	8481.	8481.	0.	424.	8057.
1981	16365.	17952.	280.	818.	15827.
TOTAL	24847.	26433.	280.	1242.	23885.

COALK V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

THIRD PARTY FINANCED/NAVY OPERATED VENTURE:
INVESTOR CASH FLOWS DURING OPERATING PERIOD
(THOUSANDS OF DOLLARS)

YEAR	LEVELIZED MINIMUM REVENUE REQUIREMENT	DEBT SERVICE INTEREST PORTION	DEBT SERVICE TOTAL	BEFORE-TAX EQUITY CASH FLOW	DEPREC-IATION	TAXABLE INCOME	TAXES	AFTER-TAX EQUITY CASH FLOW	PRESENT VALUE (PV) AT STARTUP ROE = 18.00 PCT FACTOR	PRESENT VALUE (PV) AT STARTUP ROE = 18.00 PCT AMOUNT
1982	5305.	882.	1114.	4191.	3583.	841.	420.	3770.	.847	3195.
1983	5305.	856.	1114.	4191.	5255.	-805.	-403.	4593.	.718	3299.
1984	5305.	827.	1114.	4191.	5016.	-538.	-269.	4460.	.609	2714.
1985	5305.	796.	1114.	4191.	5016.	-507.	-253.	4444.	.516	2292.
1986	5305.	761.	1114.	4191.	5016.	-472.	-236.	4426.	.437	1935.
1987	5305.	722.	1114.	4191.	0.	4583.	2292.	1899.	.370	703.
1988	5305.	679.	1114.	4191.	0.	4626.	2313.	1877.	.314	589.
1989	5305.	631.	1114.	4191.	0.	4674.	2337.	1854.	.266	493.
1990	5305.	578.	1114.	4191.	0.	4727.	2364.	1827.	.225	412.
1991	5305.	519.	1114.	4191.	0.	4786.	2393.	1797.	.191	343.
1992	5305.	453.	1114.	4191.	0.	4852.	2426.	1765.	.162	286.
1993	5305.	380.	1114.	4191.	0.	4925.	2462.	1728.	.137	237.
1994	5305.	300.	1114.	4191.	0.	5006.	2503.	1688.	.116	196.
1995	5305.	210.	1114.	4191.	0.	5095.	2548.	1643.	.099	162.
1996	5305.	110.	1114.	4191.	0.	5195.	2597.	1593.	.084	133.
TOTAL	79576.	8703.	16717.	62859.	23885.	46989.	23494.	39365.		16991.

COALR V1.0 600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

THIRD PARTY FINANCED/NAVY OPERATED VENTURE:
NAVY CASH FLOWS DURING OPERATING PERIOD
(THOUSANDS OF DOLLARS)

YEAR	LEASE COST CURRENT DOLLARS	LEASE COST CONSTANT DOLLARS	PV* FACTOR FOR LEASE	PV OF LEASE COST	OPERATING COSTS	OPERATING BENEFITS	SAVINGS (OPER. BENEFITS - COSTS)	PV FACTOR FOR SAVINGS AND OPERATING COSTS	PV OF OPERATING COSTS	PV OF SAVINGS
1982	5305.	4202.	.683	2870.	14655.	11703.	-2953.	.717	10502.	-2116.
1983	5305.	3964.	.621	2462.	15341.	12599.	-2742.	.651	9994.	-1786.
1984	5305.	3740.	.564	2111.	16078.	13567.	-2511.	.592	9522.	-1487.
1985	5305.	3526.	.513	1811.	16871.	14612.	-2259.	.538	9083.	-1216.
1986	5305.	3328.	.467	1553.	17723.	15740.	-1983.	.489	8675.	-971.
1987	5305.	3140.	.424	1332.	18641.	16958.	-1682.	.445	8294.	-749.
1988	5305.	2962.	.386	1142.	19627.	18274.	-1353.	.405	7940.	-547.
1989	5305.	2795.	.350	980.	20689.	19695.	-994.	.368	7608.	-366.
1990	5305.	2636.	.319	840.	21831.	21229.	-602.	.334	7298.	-201.
1991	5305.	2487.	.290	720.	23059.	22885.	-174.	.304	7008.	-53.
1992	5305.	2346.	.263	618.	24382.	24674.	292.	.276	6736.	81.
1993	5305.	2214.	.239	530.	25805.	26605.	800.	.251	6481.	201.
1994	5305.	2088.	.218	454.	27336.	28691.	1354.	.228	6242.	309.
1995	5305.	1970.	.198	390.	28985.	30942.	1958.	.208	6017.	406.
1996	5305.	1859.	.180	334.	30759.	33374.	2615.	.189	5805.	493.
1997	0.	0.	.164	0.	32669.	36000.	3331.	.172	5605.	571.
1998	0.	0.	.149	0.	34726.	38835.	4109.	.156	5416.	641.
1999	0.	0.	.135	0.	36941.	41897.	4957.	.142	5237.	703.
2000	0.	0.	.123	0.	39325.	45203.	5878.	.129	5069.	758.
2001	0.	0.	.112	0.	41893.	48774.	6891.	.117	4909.	806.
2002	0.	0.	.102	0.	44658.	52629.	7970.	.107	4757.	849.
2003	0.	0.	.092	0.	47637.	56792.	9155.	.097	4613.	887.
2004	0.	0.	.084	0.	50845.	61287.	10442.	.088	4476.	919.
2005	0.	0.	.076	0.	54301.	66141.	11841.	.080	4346.	948.
2006	0.	0.	.069	0.	58023.	71363.	13340.	.073	4222.	972.
TOTAL	79576.	43261.		18146.	762799.	830489.	67699.		165855.	52.

PRESENT VALUE OF COSTS = $184001. THOUSAND (LEASE PLUS OPERATING COSTS)
UNIT PRESENT VALUE = $ 3.50 PER MILLION BTU (PV / 52560. BILLION BTU)
LEVELIZED COST = $ 25715. THOUSAND (PV * .1398
UNIT LEVELIZED COST = $ 12.23 PER MILLION BTU (LEVELIZED COST / 2102. BILLION BTU)
SAVINGS/INVESTMENT RATIO = .00 (PV SAVINGS / PV LEASE)
DISCOUNTED PAYBACK PERIOD = NONE EXISTS

COALK V1.0   600,000 LB/HR DECENTRALIZED SYSTEM WITH COAL-OIL FUEL

SUMMARY:

NAVY FINANCED/NAVY OPERATED VENTURE VS. THIRD PARTY FINANCED/NAVY OPERATED VENTURE

	PRESENT VALUE REFERENCED TO DISPLAY YEAR (5/1978)	PRESENT VALUE REFERENCED TO STARTUP YEAR (5/1981)
NAVY FINANCED/NAVY OPERATED VENTURE:		
PRESENT VALUE	$184282. THOUSAND	$292131. THOUSAND
UNIT PRESENT VALUE	$ 3.51 PER MILLION BTU	$ 5.56 PER MILLION BTU
LEVELIZED COST	$ 25755. THOUSAND	$ 30574. THOUSAND
UNIT LEVELIZED COST	$ 12.25 PER MILLION BTU	$ 14.59 PER MILLION BTU
SAVINGS/INVESTMENT RATIO	.00	
DISCOUNTED PAYBACK PERIOD DOES NOT EXIST		
THIRD PARTY FINANCED/NAVY OPERATED VENTURE:		
NAVY OPERATOR		
PRESENT VALUE	$184001. THOUSAND	$291686. THOUSAND
UNIT PRESENT VALUE	$ 3.50 PER MILLION BTU	$ 5.55 PER MILLION BTU
LEVELIZED COST	$ 25715. THOUSAND	$ 30627. THOUSAND
UNIT LEVELIZED COST	$ 12.23 PER MILLION BTU	$ 14.57 PER MILLION BTU
SAVINGS/INVESTMENT RATIO	.00	
DISCOUNTED PAYBACK PERIOD DOES NOT EXIST		
PRIVATE INVESTOR		
LEVELIZED REVENUE (LEASE)	$ 5305. THOUSAND PER YEAR	
LEASE LIFE	15 YEARS	

LISTING OF DATA TABLE FILE TAB3

Appendix B

LISTING OF DATA TABLE FILE TAB3

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*
* INITIALIZE DATA TABLES
*
TABLES NEW
*
* DEFINITIONS:  K=1000, CI=COST INDEX
*
INCLUDE
*
ANNMTLC1 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MTRLS, STOKERS, BAGHOUSES,CENTRAL/
** X=STEAM KLB/H,Y=(K$/Y)/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
       100          1.58             216.8      1510.
       200          1.27             216.8      1510.
       400          1.02             216.8      1510.
       800          0.86             216.8      1510.
      1000          0.82             216.8      1510.
ANNMTLC2 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MTRLS, 2 PCT S FGD, CENTRAL/
** X=STEAM KLB/H,Y=(K$/Y),CI1=CHEM-ENG,CI2=NAVY ***
       100           103             216.8      1510.
       200           158             216.8      1510.
       400           258             216.8      1510.
       800           383             216.8      1510.
      1000           435             216.8      1510.
ANNMTLC4 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MTRLS, 4 PCT S FGD, CENTRAL/
** X=STEAM KLB/H,Y=(K$/Y),CI1=CHEM-ENG,CI2=NAVY ***
       100           127             216.8      1510.
       200           194             216.8      1510.
       400           294             216.8      1510.
       800           471             216.8      1510.
      1000           548             216.8      1510.
ANNMTLD1 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MTRLS, STOKERS, BAGHOUSES, DECENTR/
** X=STEAM KLB/H,Y=(K$/Y)/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
       100          1.84             216.8      1510.
       200          1.46             216.8      1510.
       400          1.21             216.8      1510.
       800          0.99             216.8      1510.
      1000          0.93             216.8      1510.
ANNMTLD2 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MTRLS, 2 PCT S FGD, DECENTR/
** X=STEAM KLB/H,Y=(K$/Y),CI1=CHEM-ENG,CI2=NAVY ***
       100           196             216.8      1510.
       200           240             216.8      1510.
       400           328             216.8      1510.
       800           504             216.8      1510.
      1000           580             216.8      1510.
ANNMTLD4 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MTRLS, 4 PCT S FGD, DECENTR/
** X=STEAM KLB/H,Y=(K$/Y),CI1=CHEM-ENG,CI2=NAVY ***
       100           212             216.8      1510.
       200           288             216.8      1510.
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        400          456           216.8      1510.
        800          696           216.8      1510.
       1000          798           216.8      1510.
LSODAMC2 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MTRLS, 2 PCT S LIQ SODA, CENTRAL/
** X=STEAM KLB/H,Y=(K$/Y),CI1=CHEM-ENG,CI2=NAVY ***
        100           59           216.8      1510.
        200           87           216.8      1510.
        400          137           216.8      1510.
        800          200           216.8      1510.
       1000          226           216.8      1510.
LSODAMC4 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MTRLS, 4 PCT S LIQ SODA, CENTRAL/
** X=STEAM KLB/H,Y=(K$/Y),CI1=CHEM-ENG,CI2=NAVY ***
        100           71           216.8      1510.
        200          105           216.8      1510.
        400          155           216.8      1510.
        800          242           216.8      1510.
       1000          279           216.8      1510.
LSODAMD2 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MTRLS, 2 PCT S LIQ SODA, DECENTR/
** X=STEAM KLB/H,Y=(K$/Y),CI1=CHEM-ENG,CI2=NAVY ***
        100          124           216.8      1510.
        200          148           216.8      1510.
        400          196           216.8      1510.
        800          284           216.8      1510.
       1000          320           216.8      1510.
LSODAMD4 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MTRLS, 4 PCT S LIQ SODA, DECENTR/
** X=STEAM KLB/H,Y=(K$/Y),CI1=CHEM-ENG,CI2=NAVY ***
        100          132           216.8      1510.
        200          172           216.8      1510.
        400          260           216.8      1510.
        800          380           216.8      1510.
       1000          429           216.8      1510.
ANNMANC1 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MHRS, STOKERS, BAGHOUSES, CENTRAL/
** X=STEAM KLB/H,Y=(MH/Y)/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
        100          230           1.0      1.0
        200          169           1.0      1.0
        400          129           1.0      1.0
        800          108           1.0      1.0
       1000          102           1.0      1.0
ANNMANC2 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MHRS, 2 PCT S FGD, CENTRAL/
** X=STEAM KLB/H,Y=MH/Y,CI1=CHEM-ENG,CI2=NAVY ***
        100        15050           1.0      1.0
        200        19300           1.0      1.0
        400        24700           1.0      1.0
        800        30700           1.0      1.0
       1000        33000           1.0      1.0
ANNMANC4 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MHRS, 4 PCT S FGD, CENTRAL/
** X=STEAM KLB/H,Y=MH/Y,CI1=CHEM-ENG,CI2=NAVY ***
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         100          15650           1.0      1.0
         200          20200           1.0      1.0
         400          25600           1.0      1.0
         800          32900           1.0      1.0
        1000          35650           1.0      1.0
ANNMAND1 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MHRS, STOKERS, BAGHOUSES, DECENTR/
** X=STEAM KLB/H,Y=(MH/Y)/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
         100            286           1.0      1.0
         200            210           1.0      1.0
         400            172           1.0      1.0
         800            136           1.0      1.0
        1000            127           1.0      1.0
ANNMAND2 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MHRS, 2 PCT S FGD, DECENTR/
** X=STEAM KLB/H,Y=MH/Y,CI1=CHEM-ENG,CI2=NAVY ***
         100          42200           1.0      1.0
         200          48200           1.0      1.0
         400          55400           1.0      1.0
         800          64800           1.0      1.0
        1000          68200           1.0      1.0
ANNMAND4 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MHRS, 4 PCT S FGD, DECENTR/
** X=STEAM KLB/H,Y=MH/Y,CI1=CHEM-ENG,CI2=NAVY ***
         100          42600           1.0      1.0
         200          49400           1.0      1.0
         400          58600           1.0      1.0
         800          69600           1.0      1.0
        1000          73600           1.0      1.0
LSODAHC2 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MHRS, 2 PCT S LIQ SODA, CENTRAL/
** X=STEAM KLB/H,Y=MH/Y,CI1=CHEM-ENG,CI2=NAVY ***
         100          12550           1.0      1.0
         200          14650           1.0      1.0
         400          17350           1.0      1.0
         800          20350           1.0      1.0
        1000          21422           1.0      1.0
LSODAHC4 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MHRS, 4 PCT S LIQ SODA, CENTRAL/
** X=STEAM KLB/H,Y=MH/Y,CI1=CHEM-ENG,CI2=NAVY ***
         100          12850           1.0      1.0
         200          15100           1.0      1.0
         400          17800           1.0      1.0
         800          21450           1.0      1.0
        1000          22770           1.0      1.0
LSODAHD2 TYPE 1 CURVE 4 N 5
TITLE /ANN OP, MAINT MHRS, 2 PCT S LIQ SODA, DECENTR/
** X=STEAM KLB/H,Y=MH/Y,CI1=CHEM-ENG,CI2=NAVY ***
         100          37800           1.0      1.0
         200          42200           1.0      1.0
         400          47200           1.0      1.0
         800          53200           1.0      1.0
        1000          55289           1.0      1.0
LSODAHD4 TYPE 1 CURVE 4 N 5
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TITLE /ANN OP, MAINT MHRS, 4 PCT S LIQ SODA, DECENTR/
** X=STEAM KLB/H,Y=MH/Y,CI1=CHEM-ENG,CI2=NAVY ***
      100        38000          1.0      1.0
      200        42800          1.0      1.0
      400        48800          1.0      1.0
      800        55600          1.0      1.0
     1000        57984          1.0      1.0
SGENCPC1 TYPE 1 CURVE 4 N 5
TITLE /CONSTRUCTION COSTS, STOKERS, CENTRAL PLANT/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
      100        45000          216.8      1510.
      200        38500          216.8      1510.
      400        32000          216.8      1510.
      800        27125          216.8      1510.
     1000        25700          216.8      1510.
SGENCPD1 TYPE 1 CURVE 4 N 5
TITLE /CONSTRUCTION COSTS, STOKERS, DECENTRALIZED/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
      100        49200          216.8      1510.
      200        41400          216.8      1510.
      400        34000          216.8      1510.
      800        26890          216.8      1510.
     1000        26890          216.8      1510.
POLLCPC1 TYPE 1 CURVE 4 N 5
TITLE /POLLUTION CONTROL CONSTRUCTION, CENTRAL, 1 PCT SULFUR/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
      100      12500              216.8    1510.0
      200       9500              216.8    1510.0
      400       7000              216.8    1510.0
      800       6125              216.8    1510.0
     1000       5867              216.8    1510.0
POLLCPC2 TYPE 1 CURVE 4 N 5
TITLE /POLLUTION CONTROL CONSTRUCTION, CENTRAL, 2 PCT SULFUR/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
      100      33000              216.8    1510.0
      200      26000              216.8    1510.0
      400      21250              216.8    1510.0
      800      17000              216.8    1510.0
     1000      16000              216.8    1510.0
POLLCPC4 TYPE 1 CURVE 4 N 5
TITLE /POLLUTION CONTROL CONSTRUCTION, CENTRAL, 4 PCT SULFUR/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
      100      39000              216.8    1510.0
      200      30500              216.8    1510.0
      400      23500              216.8    1510.0
      800      19750              216.8    1510.0
     1000      18600              216.8    1510.0
POLLCPD1 TYPE 1 CURVE 4 N 5
TITLE /POLLUTION CONTROL CONSTRUCTION, DECENTRAL, 1 PCT SULFUR/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
      100      15600              216.8    1510.0
      200      11200              216.8    1510.0
      400       9700              216.8    1510.0
      800       7750              216.8    1510.0
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     1000       7208                   216.8    1510.0
POLLCPD2 TYPE 1 CURVE 4 N 5
TITLE /POLLUTION CONTROL CONSTRUCTION, DECENTRAL, 2 PCT SULFUR/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
      100       49000                  216.8    1510.0
      200       32500                  216.8    1510.0
      400       25500                  216.8    1510.0
      800       20750                  216.8    1510.0
     1000       20000                  216.8    1510.0
POLLCPD4 TYPE 1 CURVE 4 N 5
TITLE /POLLUTION CONTROL CONSTRUCTION, DECENTRAL, 4 PCT SULFUR/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
      100       53000                  216.8    1510.0
      200       38500                  216.8    1510.0
      400       33500                  216.8    1510.0
      800       26875                  216.8    1510.0
     1000       26000                  216.8    1510.0
LSODACC2 TYPE 1 CURVE 4 N 5
TITLE /CONSTRUCTION COSTS, 2 PCT LIQ SODA,CENTRAL/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
      100         22750             216.8     1510.
      200         17750             216.8     1510.
      400         14250             216.8     1510.
      800         11562             216.8     1510.
     1000         10840             216.8     1510.
LSODACC4 TYPE 1 CURVE 4 N 5
TITLE /CONSTRUCTION COSTS, 4 PCT S LIQ SODA,CENTRAL/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
      100         25750             216.8     1510.
      200         20000             216.8     1510.
      400         15250             216.8     1510.
      800         12938             216.8     1510.
     1000         12270             216.8     1510.
LSODACD2 TYPE 1 CURVE 4 N 5
TITLE /CONSTRUCTION COSTS, 2 PCT S LIQ SODA, DECENTR/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
      100         32200             216.8     1510.
      200         21800             216.8     1510.
      400         17500             216.8     1510.
      800         14200             216.8     1510.
     1000         13276             216.8     1510.
LSODACD4 TYPE 1 CURVE 4 N 5
TITLE /CONSTRUCTION COSTS, 4 PCT S LIQ SODA, DECENTR/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
      100         34200             216.8     1510.
      200         24800             216.8     1510.
      400         21500             216.8     1510.
      800         17200             216.8     1510.
     1000         16007             216.8     1510.
PIPEAS20 TYPE 4 CURVE 4 N 12
TITLE /ABOVE GROUND PIPE COST PER FOOT SCHEDULE 20/
** X=INCHES DIAM,Y=$/FT,CI1=CHEM-ENG,CI2=NAVY ***
        1        41                    216.8     1510.
        2       45.3                   216.8     1510.
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         4         57.3                     216.8      1510.
         6         83.8                     216.8      1510.
         8        119.3                     216.8      1510.
        10        131.4                     216.8      1510.
        12        146.4                     216.8      1510.
        16        173.4                     216.8      1510.
        20        236.1                     216.8      1510.
        24        263.1                     216.8      1510.
        30        296.7                     216.8      1510.
        36        333.1                     216.8      1510.
PIPEAS30 TYPE 4 CURVE 4 N 12
TITLE /ABOVE GROUND PIPE, COST PER FOOT, SCHEDULE 30/
** X=INCHES DIAM,Y=$/FT,CI1=CHEM-ENG,CI2=NAVY ***
         1           41                     216.8      1510.
         2         45.3                     216.8      1510.
         4         57.3                     216.8      1510.
         6         83.8                     216.8      1510.
         8        119.3                     216.8      1510.
        10        131.4                     216.8      1510.
        12        146.4                     216.8      1510.
        16        183.8                     216.8      1510.
        20        256.8                     216.8      1510.
        24        298.7                     216.8      1510.
        30        312.9                     216.8      1510.
        36        341.5                     216.8      1510.
PIPEAS40 TYPE 4 CURVE 4 N 12
TITLE /ABOVE GROUND PIPE, COST PER FOOT, SCHEDULE 40/
** X=INCHES DIAM,Y=$/FT,CI1=CHEM-ENG,CI2=NAVY ***
         1           41                     216.8      1510.
         2         45.3                     216.8      1510.
         4         57.3                     216.8      1510.
         6         83.8                     216.8      1510.
         8        119.3                     216.8      1510.
        10        131.4                     216.8      1510.
        12        152.2                     216.8      1510.
        16        201.9                     216.8      1510.
        20        279.8                     216.8      1510.
        24        330.8                     216.8      1510.
        30        377.1                     216.8      1510.
        36        417.9                     216.8      1510.
PIPEBS20 TYPE 4 CURVE 4 N 12
TITLE /BURIED PIPE, COST PER FOOT, SCHEDULE 20/
** X=INCHES DIAM,Y=$/FT,CI1=CHEM-ENG,CI2=NAVY ***
         1         62.8                     216.8      1510.
         2         68.2                     216.8      1510.
         4         86.9                     216.8      1510.
         6        114.6                     216.8      1510.
         8        127.1                     216.8      1510.
        10        139.1                     216.8      1510.
        12        149.1                     216.8      1510.
        16        220.1                     216.8      1510.
        20        255.9                     216.8      1510.
        24        282.9                     216.8      1510.
        30        374.2                     216.8      1510.
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        36      401.1                     216.8      1510.
PIPEBS30 TYPE 4 CURVE 4 N 12
TITLE /BURIED PIPE, COST PER FOOT, SCHEDULE 30/
** X=INCHES DIAM,Y=$/FT,CI1=CHEM-ENG,CI2=NAVY ***
         1       62.8                     216.8      1510.
         2       68.2                     216.8      1510.
         4       86.9                     216.8      1510.
         6      114.6                     216.8      1510.
         8      127.1                     216.8      1510.
        10      139.1                     216.8      1510.
        12      149.1                     216.8      1510.
        16      214.1                     216.8      1510.
        20      299.1                     216.8      1510.
        24      318.5                     216.8      1510.
        30      380.9                     216.8      1510.
        36      409.6                     216.8      1510.
PIPEBS40 TYPE 4 CURVE 4 N 12
TITLE /BURIED PIPE, COST PER FOOT, SCHEDULE 40/
** X=INCHES DIAM,Y=$/FT,CI1=CHEM-ENG,CI2=NAVY ***
         1       62.8                     216.8      1510.
         2       68.2                     216.8      1510.
         4       86.9                     216.8      1510.
         6      114.6                     216.8      1510.
         8      127.1                     216.8      1510.
        10      139.1                     216.8      1510.
        12      159.9                     216.8      1510.
        16      232.1                     216.8      1510.
        20      299.6                     216.8      1510.
        24      350.7                     216.8      1510.
        30      445.1                     216.8      1510.
        36      486.0                     216.8      1510.
PIPINS2  TYPE 4 CURVE 4 N 12
TITLE /COST OF 2 INCHES OF PIPING INSULATION/
** X=INCHES DIAM,Y=$/FT,CI1=CHEM-ENG,CI2=NAVY ***
         1         11                     216.8      1510.
         2       14.7                     216.8      1510.
         4       20.1                     216.8      1510.
         6       24.5                     216.8      1510.
         8       27.8                     216.8      1510.
        10       34.4                     216.8      1510.
        12       36.8                     216.8      1510.
        16       49.1                     216.8      1510.
        20       61.2                     216.8      1510.
        24       64.6                     216.8      1510.
        30       73.3                     216.8      1510.
        36       84.3                     216.8      1510.
PIPINS5  TYPE 4 CURVE 4 N  7
TITLE /COST OF 5 INCHES OF PIPING INSULATION/
** X=INCHES DIAM,Y=$/FT,CI1=CHEM-ENG,CI2=NAVY ***
        10       60.4                     216.8      1510.
        12       80.6                     216.8      1510.
        16       95.6                     216.8      1510.
        20        125                     216.8      1510.
        24      153.9                     216.8      1510.
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         30      164.2                      216.8      1510.
         36      195.4                      216.8      1510.
PIPINS8  TYPE 4 CURVE 4 N 5
TITLE /COST OF 8 INCHES OF PIPING INSULATION/
** X=INCHES DIAM,Y=$/FT,CI1=CHEM-ENG,CI2=NAVY ***
         16      110.3                      216.8      1510.
         20      136.7                      216.8      1510.
         24      165.6                      216.8      1510.
         30      207.6                      216.8      1510.
         36      247.0                      216.8      1510.
COALEXDC TYPE 5 CURVE 4 N 4
TITLE /EXTRA CONSTRUCTION COSTS FOR COAL HANDLING, DECENT./
** X=DESIGN T/H,Y=$,CI1=CHEM-ENG,CI2=NAVY ***
          5      25000     216.8      1510
         10      40000     216.8      1510
         20      65000     216.8      1510
         40     110000     216.8      1510
COALOPS TYPE 5 CURVE 4 N 4
TITLE /COAL HANDLING FACILITY OPERATING SUPPLIES/
** X=DESIGN T/H,Y=$/Y,CI1=CHEM-ENG,CI2=NAVY ***
          5      70000     216.8      1510
         10     120000     216.8      1510
         20     190000     216.8      1510
         40     360000     216.8      1510
COALMHRS TYPE 6 CURVE 4 N 4
TITLE /COAL HANDLING FACILITY OPERATING LABOR/
** X=DESIGN T/H,Y=MH/Y,CI1=CHEM-ENG,CI2=NAVY ***
          5       7280       1.0        1.0
         10      12060       1.0        1.0
         20      14560       1.0        1.0
         40      18720       1.0        1.0
COALCONS TYPE 5 CURVE 4 N 4
TITLE /COAL HANDLING FACILITY CONSTRUCTION COST/
** X=DESIGN T/H,Y=$,CI1=CHEM-ENG,CI2=NAVY ***
          5    1100000     216.8      1510
         10    2000000     216.8      1510
         20    4000000     216.8      1510
         40    7500000     216.8      1510
COGNCPCB TYPE 10 CURVE 4  N 4
TITLE /ADDITIONAL BOILER CONSTRUCTION COSTS FOR COGENERATION/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
        100      21000                      216.8       1510
        200      20000                      216.8       1510
        400      18000                      216.8       1510
        800      15000                      216.8       1510
COGNNONC TYPE 8  CURVE 4  N 4
TITLE /TOTAL CONSTRUCTION COST, NONCONDENSING T-G SET/
** X=MEGAWATTS,Y=$/MW,CI1=CHEM-ENG,CI2=NAVY ***
        2.6     884600                      216.8       1510
        5.2     730800                      216.8       1510
      10.45     593300                      216.8       1510
       21.0     485700                      216.8       1510
COGNEXTC TYPE 8  CURVE 4  N 4
TITLE /TOTAL CONSTRUCTION COST, EXTRACTION T-G SET/
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** X=MEGAWATTS,Y=$/MW,CI1=CHEM-ENG,CI2=NAVY ***
      3.1   1064500                       216.8      1510
     6.25    816000                       216.8      1510
     12.5    656000                       216.8      1510
       25    592000                       216.8      1510
*
PCGNCPC1 TYPE 1 CURVE 4 N 5
TITLE / STEAM GENERATION - PULVERIZED/
** X=STEAM KLB/H,Y=$/(KLB/H),CI1=CHEM-ENG,CI2=NAVY ***
      200      66000      275.5      1900
      300      57300      275.5      1900
      400      49900      275.5      1900
      600      44000      275.5      1900
      900      35000      275.5      1900
*
COMCONS  TYPE 1 CURVE 4 N 3
TITLE /COAL OIL MIX FACILITY TOTAL CONSTRUCTION COST/
** X=DESIGN COM T/H,Y=$,CI1=CHEM-ENG,CI2=NAVY ***
   2.16      1300000.      315.      2054.
    5.4      2250000.      315.      2054.
   16.2      3400000.      315.      2054.
*
COMMHRS  TYPE 1 CURVE 4 N 3
TITLE /COAL OIL MIX FACILITY ANNUAL MANHOURS/
** X=DESIGN COM T/H,Y=MH/Y,CI1=CHEM-ENG,CI2=NAVY ***
   2.16        10710.      1.0        1.0
    5.4        14560.      1.0        1.0
   16.2        18190.      1.0        1.0
*
COMOPS   TYPE 1 CURVE 4 N 3
TITLE /COAL OIL MIX FACILITY ANNUAL MATERIAL COST/
** X=DESIGN COM T/H,Y=(K$/Y),CI1=CHEM-ENG,CI2=NAVY ***
   2.16          62.4      315.      2054.
    5.4         108.0      315.      2054.
   16.2         163.2      315.      2054.
*
COMEL    TYPE 1 CURVE 4 N 3
TITLE /COAL OIL MIX FACILITY ANNUAL ELECTRICITY/
** X=DESIGN COM T/H,Y=KWH/Y,CI1=CHEM-ENG,CI2=NAVY ***
   2.16       307000.      1.0        1.0
    5.4       570000.      1.0        1.0
   16.2      1577000.      1.0        1.0
*
CWMCONS  TYPE 1 CURVE 4 N 3
TITLE /COAL WATER MIX FACILITY TOTAL CONSTRUCTION COST/
** X=DESIGN CWM T/H,Y=$,CI1=CHEM-ENG,CI2=NAVY ***
      5      1130000.      315.      2054.
     15      1920000.      315.      2054.
     45      3780000.      315.      2054.
*
CWMMHRS  TYPE 1 CURVE 4 N 3
TITLE /COAL WATER MIX FACILITY ANNUAL MANHOURS/
** X=DESIGN CWM T/H,Y=MH/Y,CI1=CHEM-ENG,CI2=NAVY ***
      5         7445.      1.0        1.0
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     15        10368.          1.0         1.0
     45        16512.          1.0         1.0
*
CWMOPS   TYPE 1 CURVE 4 N 3
TITLE /COAL WATER MIX FACILITY ANNUAL MATERIAL COST/
** X=DESIGN CWM T/H,Y=(K$/Y),CI1=CHEM-ENG,CI2=NAVY ***
      5          54.2        315.       2054.
     15          92.2        315.       2054.
     45         181.4        315.       2054.
*
CWMEL    TYPE 1 CURVE 4 N 3
TITLE /COAL WATER MIX FACILITY ANNUAL ELECTRICITY/
** X=DESIGN CWM T/H,Y=KWH/Y,CI1=CHEM-ENG,CI2=NAVY ***
      5      394000.           1.0         1.0
     15     1095000.           1.0         1.0
     45     3110000.           1.0         1.0
*
STORCONS TYPE 1 CURVE 4 N 8
TITLE /COAL MIXTURE FUEL STORAGE TOTAL CONSTRUCTION COST/
** X=BARRELS STORAGE,Y=$,CI1=CHEM-ENG,CI2=NAVY ***
     4000.    120000.        315.       2054.
     8000.    200000.        315.       2054.
    16000.    300000.        315.       2054.
    32000.    500000.        315.       2054.
    64000.    800000.        315.       2054.
   128000.   1600000.        315.       2054.
   256000.   3200000.        315.       2054.
   512000.   6400000.        315.       2054.
*
STORMHRS TYPE 1 CURVE 4 N 8
TITLE /COAL MIXTURE FUEL STORAGE ANNUAL MANHOURS/
** X=BARRELS STORAGE,Y=MH/Y,CI1=CHEM-ENG,CI2=NAVY ***
     4000.      2280.          1.0         1.0
     8000.      2413.          1.0         1.0
    16000.      2580.          1.0         1.0
    32000.      2913.          1.0         1.0
    64000.      3413.          1.0         1.0
   128000.      4747.          1.0         1.0
   256000.      7413.          1.0         1.0
   512000.     12746.          1.0         1.0
*
STOROPS  TYPE 1 CURVE 4 N 8
TITLE /COAL MIXTURE FUEL STORAGE ANNUAL MATERIAL COST/
** X=BARRELS STORAGE,Y=(K$/Y),CI1=CHEM-ENG,CI2=NAVY ***
     4000.         6.        315.       2054.
     8000.        10.        315.       2054.
    16000.        15.        315.       2054.
    32000.        25.        315.       2054.
    64000.        40.        315.       2054.
   128000.        80.        315.       2054.
   256000.       160.        315.       2054.
   512000.       320.        315.       2054.
BAGCNTMR TYPE 1 CURVE 4 N 4
TITLE /ANN OP, MAINT LABOR, BAGHOUSES, CENTRAL/
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** X=STEAM KLB/H,Y= MH/Y      ,CI1=CHEM=ENG,CI2=NAV
    100        4500       1.0        1.0
    200        4750       1.0        1.0
    400        5100       1.0        1.0
    800        5950       1.0        1.0
BAGCNTMT TYPE 1 CURVE 4 N 4
TITLE /ANN OP, MAINT MTRLS, BAGHOUSES, CENTRAL/
** X=STEAM KLB/H,Y= K$/YR,CI1=CHEM-ENG,CI2=NAVY ***
    100        46    216.8     1510.
    200        67    216.8     1510.
    400        96    216.8     1510.
    800        163   216.8     1510.
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